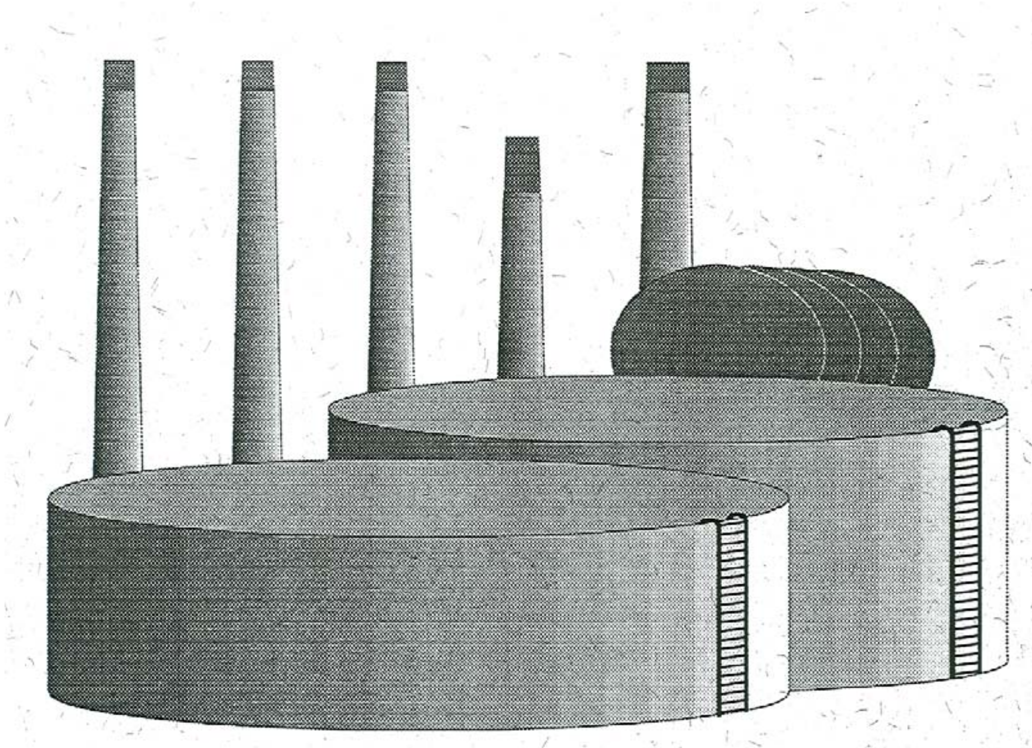

Facility Oil Handling and Design Standards Rule

Guidance Manual

WASHINGTON STATE DEPARTMENT OF ECOLOGY

January 1995

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TO: Guidance Manual Holder

This manual is intended to support compliance with *WAC 173-180A, Facility Operations and Design Standard Rule* for oil handling facilities. This manual may need to be revised periodically to ensure that the manual is functional. If you would like to receive manual updates as they are available, please submit this completed form to:

Joe Subsits
Department of Ecology
Spill Prevention/Planning Unit PO Box 47600
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STATE OF WASHINGTON
DEPARTMENT OF ECOLOGY
GUIDANCE MANUAL
FOR
FACILITY OIL HANDLING
OPERATIONS AND DESIGN STANDARDS RULE

January 1995

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STANDARD ACRONYMS

ACI	American Concrete Institute
ANSI	American National Standards Institute
API	American Petroleum Institute
ASME	American Society of Mechanical Engineers
ASNT	American Society for Non-destructive Testing
AST	Aboveground Storage Tank
ASTM	American Society of Testing Materials
AWS	American Welding Society
BOCA	Building Officials and Code Administration
CFR	Code of Federal Regulations
COTP	Captain of the Port
FPIC	Federal Person in Charge
MOP	Maximum Operating Pressure
MTR	Material Test Report
NACE	National Association of Corrosion Engineers
NAVFAC	Naval Facilities Engineering Command
NDE	Non Destructive Examination
NFPA	National Fire Protection Association
NIOSH	National Institute for Occupational Safety and Health
OSHA	Occupational, Safety and Health Administration
RCW	Revised Code of Washington
RMA	Rubber Manufacturers Association
SCADA	Supervisory Control and Data Acquisition
SPCC	Spill Prevention, Control and Countermeasures
UBC	Uniform Building Code
UFC	Uniform Fire Code
UL	Underwriters Laboratory
UT	Ultrasonic Testing
VPIC	Vessel Person in Charge
WAC	Washington Administrative Code

INTRODUCTION

The 1991 Oil Spill Prevention Act Requires the Department of Ecology to develop oil spill prevention standards that provide the "best achievable protection" of public health and the environment. The authority to adopt these standards is found in 90.56.220 RCW.

It was important that the rule development process include strong public participation. As a result of consensus reached during the public participation process, it was determined that the operations standard would be performance based, allowing flexibility needed by oil handling facilities to develop techniques best suited to their individual operating practices.

There are three reasons for developing this manual:

1. Since this is a performance based standard a forum was needed where the compliance strategies could be identified.
2. It was not feasible to cover all possible spill prevention measures in a rule. This manual describes prevention options which are recommended but not required by rule.
3. The manual will serve as a training instrument for facility and agency staff.

Large bold print represents actual rule language. The text following the rule statement represents the guidance pertaining to this language. This manual's binder format allows for revisions and updates as needed. Revisions to this manual may be warranted as experience is gained while implementing this rule. Should you have questions regarding rule interpretation, submit questions and concerns in writing to:

Department of Ecology
Spill Policy and Planning Section P.O. Box 47600
Olympia, WA 98540-7600
Attn: Joe Subsits

Ecology will respond directly to new interpretations or suggested changes to the rule. A copy of this response may be distributed to regulated facilities depending on the applicability. Responses to rule interpretations which are more involved may require formation of a workgroup to address the issue of concern. The end result of this effort could be a policy or rule change.

Supporting and background information may be found in the appendix. Refer to the table of contents for a listing of information found in the appendix.

This manual is not intended to be a substitute for the rule. If there are instances where the rule conflicts with guidance, the rule takes precedence.

Chapter 1

WAC 173-180A-010 PURPOSE

The purpose of this rule is to establish facility operations and design standards which, when followed, will:
(1 Prevent oil and petroleum spills from occurring;
(2) Ensure that facilities are designed and operated in a manner which will provide the best achievable protection of the public health and the environment;
(3) Provide improved protection of Washington waters and natural resources from the impacts of oil spills caused by improper oil handling equipment design and operations.

The purpose of this rule is consistent *with RCW 90.56* which mandates to Ecology to develop oil spill prevention operations standards and to implement an inspection program to ensure compliance with that standard. The definition of "best achievable protection" provides the guideline for developing the operations and design standard. The mandate requires Ecology to consider risks associated with oil handling operations, the level of protection provided by a prevention measure, cost, and the feasibility of implementing a prevention measure.

Chapter 2

WAC 173-180A-020 AUTHORITY

RCW 90.56.220 provides statutory authority for developing operations and design standards and implementing a compliance program established by this chapter.

Chapter 3

WAC 173-180A-030 DEFINITIONS

"Appropriate person" means a person designated by the facility as being competent and trained to implement a designated function.

This definition refers to a properly trained facility person involved with transmission pipeline transfers. Their training requirements are described and regulated under WAC 173-180C, the Facility Personnel Oil Handling Training and Certification Rule.

"Best achievable protection" means the highest level of protection that can be achieved through the use of the best achievable technology and those staffing levels, training procedures, and operational methods that provide the greatest degree of protection available. The director's determination of best achievable protection shall be guided by the critical need to protect the state's natural resources and waters, while considering: The additional protection provided by the measures; the technological achievability of the measures; and the cost of the measures.

"Best achievable technology" means the technology that provides the greatest degree of protection taking into consideration: Processes that are being developed, or could feasibly be developed, given overall reasonable expenditures on research and development; and processes that are currently in use. In determining what is best achievable technology, the director shall consider the effectiveness, engineering feasibility, and commercial availability of the technology.

"Board" means the pollution control hearings board.

"Bulk" means material that is stored or transported in a loose, unpackaged liquid, powder, or granular form capable of being conveyed by a pipe, bucket, chute, or belt system.

"Cargo vessel" means a self-propelled ship in commerce, other than a tank vessel or a passenger vessel, greater than three hundred or more gross tons, including but not limited to, commercial fish processing vessels and freighters.

"Covered vessel" means a tank vessel, cargo vessel, or passenger vessel.

"Department" means the department of ecology.

"Directly impact" means without treatment.

This term is used in the transfer pipeline definition and is intended to describe a discharge that flows directly into "waters of the state" untreated.

"Director" means the director of the department of ecology.

This term can also mean a person appointed by the director.

"**Discharge" means any spilling, leaking, pumping, pouring, emitting, emptying, or dumping.**

"Emergency shutdown" means a deliberate stoppage of equipment or facility operation under circumstances requiring immediate action to prevent or reduce loss of life, injury, oil spills or significant damage to or loss of property or environmental values.

This term is also defined in 33 CFR 154.550 and 33 CFR 155.780. The federal definition is different than the agency's definition. The federal definition establishes timing requirements for shutdown. Because of water hammer considerations, facilities may apply to the Coast Guard for a variance from this requirement. Ecology does address the variance process in order to avoid potential contradictions which may result from double regulating this particular requirement. Ecology feels that the State's definition complements the federal definition adequately.

"Facility" means any structure, group of structures, equipment, pipeline, or device, other than a vessel, located on or near the navigable waters of the state that transfers oil in the bulk to or from a tank vessel or pipeline, that is used for producing, storing, handling, transferring, processing, or transporting oil in bulk.

A facility does not include any: railroad car, motor vehicle, or other rolling stock while transporting oil over the highways or rail lines of this state; underground storage tank regulated by the department or a local government under chapter 90.76 RCW; a motor vehicle motor fuel outlet; a facility that is operated as part of an exempt agricultural activity as provided in RCW 82.04.330; or a marine fuel outlet that does not dispense more than three thousand gallons of fuel to a ship that is not a covered vessel, in a single transaction.

Tank trucks or rail cars transferring oil to a tank vessel may be covered by this rule depending on the use of the rolling stock. The legislature did not want rolling stock used as a storage tank

exempted from coverage. Consequently, rolling stock which is clearly used for the transport and delivery of oil is not covered by this rule (The Coast Guard would cover this type of operation). However, rolling stock which is used primarily as a stationary storage tank would be covered by this rule. There may be instances where an individual determination of applicability will need to be made on a case by case basis.

"Facility person in charge" means the person designated under the provisions of 33 C.F.R 154.710.

"Navigable waters of the state" means those waters of the state, and their adjoining shorelines, that are subject to the ebb and flow of the tide and/or are presently used, have been used in the past, or may be susceptible for use to transport intrastate, interstate, or foreign commerce.

"Immediate threat" means threat which could cause loss of life, reduce safety or adversely impact waters of the state or environment.

"Oil" or "oils" means naturally occurring liquid hydrocarbons at atmospheric temperature and pressure coming from the earth, including condensate and natural gasoline, and any fractionation thereof, including, but not limited to, crude oil, petroleum, gasoline, fuel oil, diesel oil, oil sludge, oil refuse, and oil mixed with wastes other than dredged spoil.

Oil does not include any substance listed in Table 302.4 of 40 C.F.R. Part 302 adopted August 14, 1989, under section 101(14) of the federal Comprehensive Environmental Response, Compensation, and Liability Act of 1980, as amended by P.L. 99-499.

"Offshore facility" means any facility, as defined in this section, located in, on, or under any of the navigable waters of the state, but does not include a facility any part of which is located in, on, or under any land of the state, other than submerged land.

"Onshore facility" means any facility, as defined in this section, any part of which is located in, on, or under any land of the state, other than submerged land, that because of its location, could reasonably be expected to cause substantial harm to the environment by discharging oil into or on the navigable waters of the state or the adjoining shorelines.

"Owner or operator" means: In the case of a vessel, any person owning, operating, or chartering by demise, the vessel; in the case of an onshore or offshore facility, any person owning or operating the facility; and in the case of an abandoned vessel or onshore or offshore facility, the person who owned or operated the vessel or facility immediately before its abandonment.

"Operator" does not include any person who owns the land underlying a facility if the person is not involved in the operations of the facility.

"Person" means any political subdivision, government agency, municipality, industry, public or private corporation, co partnership, association, firm, individual, or any other entity whatsoever.

"Pipeline operator" means the operator of a transmission pipeline.

"Process pipelines" means a pipeline used to carry oil within the oil refining/processing units of a facility, process unit to tankage piping and tankage interconnecting piping. Process pipelines do not include pipelines used to transport oil to or from a tank vessel or transmission pipeline.

"Secondary containment" means containment systems which prevent any materials discharged from reaching the waters of the state.

"Ship" means any boat, ship, vessel, barge, or other floating craft of any kind.

"Spill" means an unauthorized discharge of oil which enters waters of the state.

An authorized discharge is a discharge which complies with chapter 90.48 RCW which is the state's Water Pollution Control Law.

"State" means the state of Washington.

"Storage tank" means all aboveground containers connected to transfer pipelines or any aboveground containers greater than ten thousand gallons (two hundred thirty-eight barrels), including storage and surge tanks, used to store bulk quantities of oil. Storage tanks do not include those tanks regulated by chapter 90.76 RC, rolling stock, wastewater treatment equipment, process pressurized~ vessels or other tanks used in the process flow through portions of the facility.

The Department feels that the primary risks associated with storage tanks are overfill, tank bottom corrosion and structural failure. The storage tank requirements attempt to address these areas. Underground storage tanks are not regulated by these regulations if they are regulated by WAC 173-360, Underground Storage Tank Regulations. Wastewater treatment equipment and pressurized process vessels are not addressed in this rule because these tanks present a lower risk to "waters of the state." They are generally instrumented, closely monitored, and located within the facility drainage area where a potential discharge could be controlled. This equipment may be regulated under the prevention plan requirements if consistent with the definition of best achievable protection.

"Tankage interconnecting piping" means buried or aboveground piping used to carry oil between storage tanks.

"Tank vessel" means a ship that is constructed or adapted to carry, or that carries, oil in bulk as cargo or cargo residue, and that:

Operates on the waters of the state; or

Transfers oil in a port or place subject to the jurisdiction of this state.

"Transmission pipeline" means a pipeline whether interstate or intrastate, subject to regulation by the United States Department of Transportation under 49 C.F.R. 195, as amended through December 5, 1991, through which oil moves in transportation, including line pipes, valves, and other appurtenances connected to line pipe, pumping units, and fabricated assemblies associated with pumping units.

"Transfer" means any movement of oil between a tank vessel or transmission pipeline and the facility.

"Transfer pipeline" is a buried or aboveground pipeline used to carry oil between a tank vessel or transmission pipeline and the first valve inside secondary containment at the facility provided that any discharge on the facility side of that first valve will not directly impact waters of the state. A transfer pipeline includes valves, and other appurtenances connected to the pipeline, pumping units, and fabricated assemblies associated with pumping units. A transfer pipeline does not include process pipelines, pipelines carrying ballast or bilge water, transmission pipelines, tank vessel or storage tanks. Instances where the transfer pipeline is not well defined will be determined on a case-by case basis.

This definition is intended to cover the portion of facility piping with the greatest potential of impacting waters of the state in the event of a spill. Pipelines which run from the dock to the facility present a greater risk than other facility pipelines because:

- are usually located in part directly over the water,
- may be subject to threat of third party damage;
- generally are not contained within the facility drainage system where a potential discharge can be controlled; and
- have little or no instrumentation which would allow the facility to immediately ascertain the status of pipeline operation.

There is a concern that transfer pipelines are defined as extending too far into the facility piping network, since transfer pipelines are required to have leak detection. Because some leak detection systems may require instrumentation, the use of this equipment may be complicated when manifolds branch into several piping networks. The definition of transfer pipeline must consider environmental and practical implications. Because of differences in facility configuration, the Ecology definition of transfer pipeline may be different from the Coast Guard definition.

Ballast and bilge water pipelines are exempted from this definition because there are greater benefits to having these waters properly treated onshore than discharged directly into open seas. It is felt that regulating this type of wastewater could discourage onshore disposal.

"Vessel person in charge" means the person designated under the provisions of 33 C.F.R. 155.700.

'Waters of the state" include lakes, rivers, ponds, streams, inland waters, underground water, salt waters, estuaries, tidal flats, beaches and land adjoining the seacoast of the state, sewers, and all other surface waters and watercourses within the jurisdiction of the state of Washington.

Chapter 4

WAC 173-180A-040 APPLICABILITY

Onshore and offshore facilities shall meet the requirements of this section. This rule does not apply to portions of a facility regulated by 49 C.F.R. 195.

This rule exempts interstate pipelines regulated by *49 CFR 195* which is the Department of Transportation Office of Pipeline Safety transmission pipeline rule. The state does have the authority to regulate intrastate pipelines covered by *49 CFR 195* as long as state regulations are as stringent or more stringent than the federal rule.

Chapter 5

WAC 173-180A-050 COMPLIANCE SCHEDULE

(1) Facilities must comply with this rule thirty-six (36) months after its effective date. Facilities needing additional time to comply with this rule must obtain written approval from the department extending this date and must submit a proposed compliance schedule to the department within eighteen months of the effective date of this rule subject to the following provisions:

The effective date of the rule is June 2, 1994. Facilities will be required to comply with these requirements by June 2, 1997 unless a compliance schedule is submitted to the department by December 2, 1995.

(a) Compliance schedules must include a justification of need for additional time. Facilities shall cite the specific requirements of this rule which will be addressed by the proposed compliance schedule.

(b) Compliance schedules shall contain target dates for the commencement and completion of projects leading to the ultimate compliance with all provisions of this rule.

(c) Only requirements which cannot be met within thirty-six months of the effective date of this rule need to be identified in the compliance schedule.

(d) Compliance schedules which do not meet the definition of best achievable protection will not be approved by the department.

The Department will approve compliance schedules which are reasonable. The facility should be able to comply with most of the requirements in this rule within the three year period. The need for a compliance schedule is primarily anticipated for facilities which have many storage tanks or smaller facilities which may need additional time to comply because of financial impacts. Compliance schedules should reflect priorities to provide the best immediate protection.

(e) It shall be legal to operate a facility if a proposed compliance schedule has been submitted to the department and the department has not provided the facility with a formal response.

(2) Facilities with approved compliance schedules must:

(a) Meet all requirements of this rule not specifically addressed in the compliance schedule.

Compliance schedules are granted only for the specific requirements which an extension has been granted. Facilities with schedules are expected to comply with the remaining requirements not covered by the compliance schedule by June 2, 1997.

(b) Submit a progress report to the department every six months following the compliance schedule approval date.

(c) Meet all compliance schedule dates unless written approval is received from the department.

(3) Facilities commencing construction thirty-six months or later after the adoption date of this rule shall meet the provisions of this rule at the time they commence operation. Facilities under design or construction at the time of the adoption of this rule shall comply with this rule thirty-six months after the adoption date of this rule.

Chapter 6

WAC 173-180A-060 VESSEL TRANSFER REQUIREMENTS

The potential for an oil release into the environment is greatest during startup and shutdown of oil transfer operations. Releases may result from human error and/or equipment failure that often can be prevented. The following regulatory requirements and recommended practices will help prevent or minimize the impact of accidental oil releases into the environment.

Oil releases caused by human error can be minimized by the provision and implementation of practical written operating procedures as covered in *WAC 173-180B of the Facility Oil Handling Operations Manual Rule*.

The facility operator and marine carrier must monitor aspects of oil transfer and take immediate action to stop the flow of oil when the working capacity of receipt tanks has been reached or when an equipment failure or other emergency occurs.

(1) General requirements.

(a) No person shall conduct an oil transfer operation to or from a tank vessel unless the facility person in charge (FPIC) and the vessel person in charge (VPIC) have:

(i) Conducted a pretransfer conference as described in 33 C.F.R. 156.120(w) as amended on September 4,1990;

Safe, spill-free oil transfer operations are dependent on effective communication and coordination between oil facility personnel and vessel personnel. The exchange of information before transfer operations begin is most important. Washington State's Facility Operations and Design Standard Rule requires that this communication/coordination take place in accordance with Coast Guard Regulation *33 CFR 156.120 (w), September 4/90*.

The office of Marine Safety (OMS) requires that vessels receiving bunkers to conduct a face-to-face pretransfer conference prior to commencing a bunkering operation. Also, OMS requires that the receiving vessel have someone on board who is proficient in English during the pretransfer conference. An interpreter must be present if someone not proficient in English is on the vessel. These requirements are described in *WAC 317-40-070* and do not apply to facilities but do impact facility operations when bunkers are delivered to vessels.

Prior to the arrival of a vessel or barge at the facility, the facility operator may acquire from the tank vessel or barge or from its owners, operators or agents, the information on the following items when applicable but not limited to: draft and trim, tank cleaning and crude washing operations, repairs that could delay commencement of cargo transfer, manifold details, nature and quantity of slops and ballast, and vessel defects.

Prior to arrival at the facility, the facility operator should provide, as requested by the tank vessel or barge, information which might include: least depth of water while the vessel is at berth, mooring accessories, manifold, hose , loading arm details, crude washing and tank cleaning requirements, and any other information pertinent to available port services, mooring and cargo transfer operations.

Pretransfer Conference-Exchange of Information Upon Arrival

Transfer operations shall not begin until both persons in charge have agreed to commence transfer operations after having conducted a face to face pre-transfer conference.

The FPIC and the VPIC shall hold a face to face pre-transfer conference, to ensure that each person in charge clearly understands the following details and procedures of the transfer operation required in *Federal Regulation 33 CFR 156*:

- the identity of the product to be transferred;
- the sequence of transfer operations;
- the transfer rate;
- the name or title and location of each person participating in the transfer operation;
- details of the transferring and receiving systems;
- critical stages of the transfer operation including changing over and topping off tanks;
- federal, state, and local rules that apply to the transfer of oil;
- emergency procedures;
- discharge containment and reporting procedures;
- shift and vessel watch arrangements including deck rover watch and point of transfer watch onboard vessels receiving bunkers;
- transfer shutdown procedures;
- communications between vessel and facility to compare and confirm quantities transferred and received; and
- signals to be used for standby, slowdown transfer rate, stop transfer, and emergency shutdown in case of a breakdown of communication system.

The facility person in charge may consider discussing other details during the pretransfer conference where applicable. These include details such as quantities and temperatures of the products to be transferred, characteristics of the product to be transferred, maximum allowable working pressure and temperature, control of pressure lines, location of pressure gauges, relief valve settings and their discharge direction, hose and loading arm limitations, and topping off transfer rates.

Additional details which may be reviewed during the pretransfer meeting may be found in *Federal Regulation 33 CFR 156.120 (w)* and *Chapter 3 and 5 of "International Safety Guide for Oil Tankers and Terminals."*

Connections

(ii) Ensured that transfer connections have been made as specified in 33 C.F.R. 156.130 as amended on September 4, 1990;

Marine Transfer Operations require that temporary connections be made in an oil transfer system. Proper connections are therefore essential for safe, leak-free operations.

Particular attention must be given to proper gasketing and bolting of flanged connections. Leaking connections are cause to inspect gasketing and replace if damaged or worn. Other types of quick connect couplings must be approved for use by the Coast Guard authority. Fire rating of quick connect couplings should be taken into consideration.

Specific requirements concerning connections can be found in *Federal Regulation 33 CFR 156.130, September 4/90.*

Declaration of Inspection

(iii) Completely filled out and signed the declaration of Inspection as required by 33 C.F.R. 156.150 as amended on September 4, 1990.

A Declaration of Inspection form shall be completed for each vessel/facility transfer operation. The declaration of inspection may be in any form but must contain, at a minimum, the information outlined in Coast Guard Regulation *33 CFR 156.150, September 4/90*. Completion of this form requires that key aspects of a transfer are reviewed prior to start of operations. It covers moorings, transfer hose, loading arms, connections, emergency shutdown, and pumping sequence.

The Declaration of Inspection form must be completed and signed by the FPIC and VPIC prior to start of operations and a copy kept on file at the facility for a minimum of one month after completion of the transfer. The form shall be available for inspection by governing authorities.

Mooring

Coast Guard Regulation 33 CFR 156.120(a) amended September 4/90 requires that vessel moorings are strong enough to hold during all expected conditions of surge, current and weather. In addition, mooring lines must be long enough to allow adjustment for changes in draft, drift and tide during transfer operations.

Mooring lines and conditions vary from port to port, therefore, mooring lines should be consistent with any local regulations in effect. Moorings must be monitored while a tanker or vessel is docked at a facility. The vessel is responsible for careful tending of her moorings, however, the facility person in charge (FPIC) should be satisfied that monitoring is adequate. Safe transfer operation is an overriding consideration in transfer requirements.

The Oil Companies International Marine Forum (OCIMF) Publication "*Guidelines and Recommendations for the Safe Mooring of Large Ships at Piers and Sea Islands"* may be referenced for additional information on mooring.

Containment Booms

The purpose of the Facility Operations and Design Standard Rule is to help prevent oil releases from occurring. However, accidental oil spills may occur, therefore, it is important that the impact of oil discharges on the environment be minimized. If an oil spill should occur during a transfer operation, the operation shall be stopped. Containment equipment and material shall be deployed in an expedient manner to minimize the impact of the spill on state water and the environment. Procedures for spill containment should be described in the facility contingency plan.

WAC 173-181 Facility Contingency Plan and Response Contractor Standards and *Coast Guard Regulation 33 CFR 154.545, September 4/90* outline specific containment requirements.

It should be noted that each facility must establish boom deployment time standards which shall be approved by the Captain of the Port (COTP). Deployment timing should be based on the criteria outlined in *WAC 173-181 and 33 Ch R 154.545*.

Specific boom types, skimming equipment, cleanup materials and deployment techniques, should be engineered on a facility specific basis.

Some facilities preboom vessels prior to transfer. This is recommended when conditions allow for practical and safe deployment. Factors which impact the feasibility of prebooming are currents, weather and type of product being transferred.

Lighting

Oil transfer facilities must have fixed lighting that adequately illuminates all transfer connection points and the transfer operations work area in general. Coast Guard Regulation 33 CFR 154.570 requires minimum lighting of 5.0 foot candles at transfer connection points, and 1.0 foot candles in transfer operations work areas. Lighting must not mislead or interfere with navigation on the adjacent waterway. In addition, lighting devices and switches must meet electrical area classification requirements for hazardous and non-hazardous areas in accordance with API RP500A (latest edition). Hazardous areas should use wiring and equipment conforming to Class 1, Group D rating either Divisions 1 or 2.

A foot candle is the illumination provided by a light source of one candle at a distance of one foot. One foot candle is equal to 10.76 lux. For the purpose of comparison the following figures are presented:

Full moonlight illumanance on the earth's surface .02 Foot-candles

A dimly lit corridor 2-3 Foot-candles

Steady reading conditions 10 Foot-candles

Workshop requirements 30-100 Foot-candle

A clear blue day 185 Foot-candles

Portable lighting or lighting provided by the marine vessel may be used for small or remote facilities when authorized by the COTP. Portable lighting must be adequate and shall conform to the requirements of the electrical area classification in which it is used. Portable lighting must not impair vessel navigation.

Light levels may be measured using commercially available light meters. The location of light level measurements should take into account facility critical and non-cziticai work areas and should be taken consistently over time.

Communications

(iv) Established adequate communication in English between the vessel and the facility and in accordance with 33 C.F.R. 154.560 as amended on September 4, 1990.

Effective, continuous two-way voice communication between the person in charge of the transfer facility and the person in charge of the transfer on the tank vessel is required by *Coast Guard Regulation 33 CFR 154.560, September 4/90*. Ecology requires that communication be in English The system must work properly during all phases of the transfer operation. If two-way radios are used during the transfer of flammable or combustible liquids, they must be intrinsically safe, as defined in *Regulation 46 CFR 110.15 -100(i)*. In addition, radios must meet Class I, Division I, Group D electrical requirements (i.e., must be explosion proof type).

If telephones or radio telephone systems are used, they must also be intrinsically safe when used in classified areas in the transfer facility.

The provision of effective voice communications, including a backup system between the transfer facility and the vessel, is the responsibility of the shore facility.

Portable VHF/UHF radios meeting explosion proof requirements are an effective communication alternative and are recommended for voice communications. The use of one VHF/UHF channel by more than one shore facility/vessel combination should be avoided.

(v) Ensured that the available capacity in the receiving tank(s) is (are) greater than the volume of oil to be transferred and all other tank fill valves which could influence the routing of the transferred oil are properly aligned.

Correct operation of valves is a prerequisite for safe, spill free transfer operations. Valve operation shall be supervised by the facility person in charge (FDIC) of the shore facility and by the vessel person in charge (VPIC) of the vessel. Sequence of valve operations should be communicated and documented in the pre-delivery meeting.

Valves should be clearly identified as to their service. Color coding, stenciling and tagging are means of identifying valves. A consistent system should be used throughout each facility.

Transfer Verification

(b) The operator shall verify that the designated storage tanks are receiving oil at the expected rate.

This requirement is intended to be a rough form of leak detection by ensuring that oil flow reaches its intended destination. Comparing pumping rates to tank gauging and computer readouts or snapping tables may be used to ensure that there are no major leaks, valve alignment is correct, successful tank switching during transfer has occurred or storage tanks are at the expected levels.

Ecology Inspections

(c) For the purpose of scheduling inspections, the department may require a facility operator to provide a twenty-four hour advance notification with updates to the department of any anticipated transfer of bulk oil by a facility operator. The department shall notify the facility in writing when this procedure will be required.

Ecology may periodically wish to conduct an inspection of a facilities transfer operation during an actual transfer. The department will request the facility to provide a 24 hour notification in advance of a transfer when an inspection is desired. Notice shall be made in person, by telephone, by facsimile machine, or by submission of a written schedule to the inspector who requested the notification.

For operations where the facility operator has less than 24 hours advance notice of the transfer, the facility operator shall provide the department with notice of the transfer as soon as possible after receiving notice of the expected transfer and prior to the start of transfer operations.

The notification should include the following information:

- Location of the transfer
- Expected time of arrival of the vessel
- Name of vessel or barge involved
- Type of oil to be transferred
- Anticipated start time of actual transfer operations

Person in Charge

(d) Transfer operations shall be supervised by the appropriate person in charge in accordance with 33 C.F.R. 156.160 as amended on September 4, 1990.

Effective coordination and supervision of oil transfer operations is the key to spill and accident free operations. Accordingly, regulations require that an oil facility operator appoint a person to be in charge of shore-side transfer operations when receiving or delivering oil. This person must be designated as the facility person in charge (FPIC) and must receive adequate training for the job. *Coast Guard Regulation 33 CFR 154.710, September 4/90* outlines minimum qualifications for the FPIC.

Periodic retraining is recommended and is essential after any facility modifications which change transfer operation. Facility training certification and training programs must be consistent with the Facility Personnel Oil Handling Training and Certification Rule (*WAC 173-180C*).

Similarly, each vessel shall designate a person in charge of the transfer (VPIC).

Emergency Shutdown

(e) Each FPIC shall ensure that the means of operating the emergency shutdown is immediately available while oil is being transferred between the facility and the vessel.

Transfer facilities must have a means by which the flow of oil between shore tanks and a vessel can be stopped in the event of an emergency. The emergency shutdown system may be an electrical, mechanical or pneumatic system linking ship and shore or a manned electronic voice communication system. The emergency shutdown point (valve) should be located near the dock to minimize an oil release in the event of a system rupture. Specific requirements are outlined in *Coast Guard Regulation 33 CFR 154.550, September 4/90.*

If an electrical, mechanical or pneumatic system is being used, the emergency shutdown system should be tested a minimum of once per year to ensure it is functioning properly and stops flow within shutdown times required by *Regulation 33 C1,R 154.550, September 4/90*.

Closure speeds of valves must take into account hydraulic line shock (water hammer). A qualified engineer or person familiar with fluid flow mechanics and dynamics should be used to assess hydraulic shock in transfer lines. This must be done on a facility specific basis.

Transfer Equipment

> **(f) Transfer equipment requirements shall meet the conditions of 33 C.F.R. 154.500 through 33 C.F.R. 154.545 as amended on September 4, 1990.**

Hose Assemblies

Hose assemblies are commonly used for oil transfer operations from vessel to onshore facilities where hose size and weight allows for manual handling of the equipment. Hose assemblies for oil transfers are best suited for low to moderate transfer frequency operations. Alternative loading arm assemblies should be considered for frequent, high flow rate operations.

Hoses used for oil transfer operations must meet minimum burst pressure of at least 600 pounds per square inch (lb/sq in) and at least four times the sum of the pressure of the relief valve settings (or four times the maximum pump pressure when no relief valve is installed) plus the static head pressure at the point where the hose is installed. The maximum allowable working pressure for each hose assembly must be at least 150 lb/sq in and more than the sum of the pressure of the relief valve settings (or the maximum pump pressure when no valve is installed) plus the static head at the point where the hose is installed. Specific requirements can be found in *Coast Guard Regulation 33 CFR 154.500*. Each hose must be marked with the words "Oil Service" and the maximum allowable working pressure. In addition, the date the hose was manufactured and the date of the latest hose pressure test may be marked on the hose or recorded elsewhere at the facility.

Marine transfer hose may be made of reinforced rubber construction reinforced thermoplastic composite construction or flexible metallic braid or metallic corrugated construction. All types must meet Coast Guard regulations and be tested at a minimum of 1.5 times rated working pressure.

Composite hose products offer extensive chemical compatibility for both hazardous and aggressive media in addition to a wide range of operating temperatures.

Non-metallic hoses must be suitable for oil (hydrocarbon) service.

Hose connections may be either threaded, flanged or quick disconnect couplings. Flanges shall meet *ANSI Standard B16.5* for steel and *B16.24* for brass or bronze flanges.

Quick disconnect couplings shall meet *ASTM Standard F-1122*.

Loading Arms

Mechanical loading arms may be used in lieu of hoses and are best suited for frequent or high volume transfer operations. When high temperatures or pressures are involved in the transfer, mechanical loading arms offer a practical alternative to hoses.

Loading arms put into service after June 30, 1973 must meet *ANSI Standard B31.3* and must be so marked or a record of manufacture to this standard kept at the facility. The equipment shall be designed to withstand 1.5 times the maximum operating pressure the transfer system has been designed for. The equipment shall also be designed for service at the maximum expected operating temperature.

Adjustable, slow opening and closing valves should be used in the design of the loading arm to limit hydraulic line shock when stopping flow and to limit static charge build-up during initial filling of the vessel compartments during filling operations.

Loading arms must be equipped with closure devices which allow for a spill free disconnection or a means of being drained prior to disconnection.

Closure Devices

Transfer hoses or loading arms must be blanked off when not in use for oil transfer operations. This practice reduces the risk of incorrect hose connection and potential oil spills. New hoses that are clearly not in service are exempted from this coast guard oil regulation requirement.

Hose blanking can be accomplished by using valves or blank flanges. Loading arms shall be equipped with appropriate dry disconnect closure devices acceptable to the Captain of the Port U.S. Coast Guard (COTP).

Small Discharge Containment

Transfer operations by their very nature present exposure to small oil releases, as the oil movement system must be opened or closed to effect connection to discharge and receiving facilities. This exposure to small oil releases increases with increased transfer frequency.

A key strategy to minimize oil releases to state waters is to ensure small discharge containment facilities are incorporated into an oil facility transfer equipment area. *Coast Guard Regulation 33 CPR 154.530 amended September 4/90* outlines specific minimum requirements.

Catchment and containment can be accomplished with permanently installed drip pans, curbing or catch basins. Often it is practical to connect the various catchment components to a common sump or underground oily tank for ease of disposing of the discharged oil in a safe and expedient manner. Underground collection tanks and sumps may be equipped with pump out facilities and level alarms to indicate when the tank needs to be emptied.

If fixed catchment and containment facilities are not feasible, portable equipment acceptable to the COTP may be used. Portable means must have a capacity of not less than one half barrel.

Equipment Testing

> **(g) Transfer equipment shall be tested in accordance with procedures identified in 33 C.F.R. 156.170 as amended on September 4, 1990. Transfer hoses shall be tested at intervals not exceeding twelve months in accordance with the procedures identified by the RMA/IP-11-4, Rubber Manufacturers Association Manual for Maintenance, Testing and Inspection of**

Hose dated 1987 or the manufacturer's recommendations for testing.

Hydrostatic Pressure Testing - Piping

Each loading arm and oil transfer piping system must be hydrostatically tested annually at a static liquid pressure of not less than 1.5 times the maximum allowable working pressure of the system Refer to *Coast Guard Regulation 33 CFR 156.170 (c) and (f).* Water or low vapor pressure liquids can be used for the test fluid. High vapor pressure liquids should not be used as the test medium since vaporization due to sunlight heated pipelines is a concern. If hydrocarbon liquid is used for testing, contingency plans should be in place to protect against oil release to state waters in the event of leakage during testing. Multi-phase fluids are not recommended as test mediums.

Transfer systems that leak during testing shall be repaired and retested. Hydrostatic Pressure Testing –

Hoses

Each non-metallic transfer hose shall be tested in accordance with *Coast Guard Regulation 33 CFR 156.170 as amended on September 4, 1990*. Hoses shall be hydrostatically tested at 1.5 times the maximum allowable working pressure rating for the hose. Testing shall be done in accordance with the procedures outlined in the Rubber Manufacturers Association Manual for 'Maintenance Testing and Inspection of Hose', *Bulletin RMA IIP-11-4 revised 1987* or the manufacturers recommendation. RMA procedures are described in appendix L.

The following hydrostatic pressure testing procedures should be followed and are found in *RMA IIP-11-4* for hoses greater than 3 inches in diameter.

All new hose or recoupled hose shall be tested prior to being placed into service. Hose assemblies that have been subjected to severe end flattening, crushing or sharp kinking shall be immediately inspected and retested. All in-service hose must be hydrostatically tested a minimum of once per year, in accordance with *Coast Guard Regulation 33 CFR 156.170 (f).*

To remain in service, hoses must not burst, bulge, leak or abnormally distort during the pressure test. Rubber hose which fails to meet elongation test limits as outlined in *RMA/IP11-4/1987*, must be removed from service.

Composite thermoplastic hose may elongate more than other hose types when under pressure. Composite hose which fails to meet manufacturers recommended elongation test limits must be removed from service.

Visual Inspection - Hoses

During visual inspection, the entire external surface of the hose must be accessible. Each hose must be free of =repaired loose covers, kinks, bulges, soft spots or any other defect which would permit the discharge of oil. Any cuts, gouges, or tears in the cover, down to, but not into the outer reinforcement, should be repaired before the hose is returned to service. If the reinforcement is cut or damaged, the hose shall be removed from service.

The hose carcass should be inspected for broken reinforcement as evidenced by permanent distortion, ridges or bulges. Evidence of hose coupling or nipple slippage and or reinforcement damage is cause for rehydrostatically testing the assembly. Cracked or heavily corroded flanges, couplings, and nipples should be replaced and the assembly rehydrostatically tested.

Internal Inspection

Coast Guard Regulation 33 CFR 156.170 (c) requires that the transfer hose have no external or internal deterioration which would cause the hose to leak when in service. A vacuum test is recommended as a means of checking for internal hose deterioration on oil suction discharge hoses. Rubber Manufacturers Association Bulletin *RMA/IP-11-4/1987* procedures for vacuum testing should be followed.

A vacuum of 20 inches of mercury (67.5 kPa) held for 10 minutes should be used. Noticeable bulges or separation of the tube from the carcass, any tear, cut or gouge through the tube is cause to remove the hose from service.

Electrical Continuity Tests - Hose

Electrically bonded hose assemblies shall be tested to verify that the electrical resistance, measured from end of nipple to the end of the opposite nipple does not exceed 0.5 OHM per foot (1.5 OHM per meter). Measurements shall be made during and after hydrostatic testing at the rated working pressure, and after vacuum testing.

Electrically discontinuous hose assemblies shall be tested with a insulation tester to verify that the electrical resistance measured from end of nipple to end of nipple is at least 100,000 OHM's.

(h) All transfer operations shall be in accordance with operations manuals approved under chapter 173-180B WAC.

(i) The FPIC shall refuse to initiate or shall cease transfer operations with any vessel which has not provided complete Information as required by the declaration of inspection, has refused to correct deficiencies identified by the FPIC during the pretransfer conference, or does not comply with the facility operations manual or facility requirements.

Oil Spills

(2) Oil spills.

(a) Any person conducting an oil transfer shall stop the transfer operation whenever oil from any source associated with the transfer is spilled into the water, or discharged onto the facility deck or dock outside secondary containment, or upon the shoreline adjoining the transfer area.

(b) Transfer operations may not resume after a spill until:

Transfer operations in this section refers to normal operations rather than a remedial action needed to reduce spill risk If the safety and risk associated with an incident is dependent on a vessel emptying its cargo, best judgment should prevail in remediating the incident.

(i) Notification has been made in accordance with RCW 90.56.280; and

(ii) The FPIC and the VPIC have determined that there is no longer an immediate threat to waters of the state or public health.

(c) The department may require that transfer operations stopped under subsection (2)(a) of this section may not resume unless authorized by the department.

(3) Suspension of transfer operations for immediate threat.

(a) The director may order a facility to suspend transfer operations if there is a condition requiring immediate action to prevent the discharge or threat of discharge of oil or to protect the public health and safety, and the environment.

(b) An order of suspension may be made effective immediately.

(c) An order of suspension shall specify each condition requiring immediate action.

(d) The transfer operation shall remain suspended until the director has determined that the need for immediate action is no longer necessary and has notified the facility operator of that determination.

(e) The director shall notify the facility operator as soon as possible of the determination that the need for immediate action is no longer necessary.

(f) The facility operator may petition the pollution control board, in writing or in any other manner, to reconsider an order of suspension.

GENERAL CONSIDERATIONS

Fire Protection Equipment

Electrical (static electricity) insulating and grounding equipment should be considered for transfer facility system design to provide vessel insulating and grounding prior to conducting a transfer operation. *The International Safety Guide for Oil Tanker and Terminal. Chapter 6 'Precautions Before and During Cargo Handling and Other Cargo Tank Operations,"* and *API publication 2003, "Protection Against Ignitions Arising Out of Static Lightening and Stray Currents"* address these requirements.

For large high volume transfer facilities, fixed fire fighting systems should be considered. These may be open or closed looped firewater/hydrant systems or fixed foam facilities. These types of systems should be designed and engineered to meet the special fire safety requirement of the transfer facility in question. *NFPA* and industry standards should be used for the design of fixed systems.

Dock and Piling Structures

Sound marine structures are important in maintaining facility safety and proper operations. Since there is not a significant amount of data which attributes oil spill cause to marine structure failure, the importance of inspecting, maintaining and repairing these structures may go unnoticed. Marine structures are subject to harsh environments which may cause erosion, corrosion or deterioration. The operator should be aware of the condition of marine facility structures and, when necessary, take appropriate action to ensure marine structure integrity. Some engineers use bridge standards from the *American Association of State Highway and Transportation Officials, American Institute of Timber Construction or the American Wood preservers Association* to evaluate the integrity of marine docks and pilings.

Chapter 7

WAC 173-180A-070 TRANSMISSION PIPELINE TRANSFER REQUIREMENTS

The following is intended to clarify transmission pipeline oil transfer compliance requirements and compliance alternatives.

(1) General requirements.

(a) No person shall conduct an oil transfer operation to or from a transmission pipeline unless the appropriate person and the pipeline operator have:

(i) Conducted pre transfer communications which identify:

(A) Type of oil;

(B) Transfer volume;

(C) Flow rates;

(D) Transfer startup or arrival time.

Delivery Coordination

Safe, spill free pipeline transfers are dependent on accurate communications and effective coordination between oil handling facility personnel and pipeline carrier scheduler, dispatcher and control room operator.

Washington State's Facility Operations and Design Standard Rule requires that this communication/coordination takes place prior to conducting a transmission pipeline transfer.

Batch Plan and Delivery Schedule

Prior to commencing a batch or delivery pumping into the transmission pipeline, the oil facility scheduler and pipeline carrier's scheduler shall identify the following:

a) Desired total delivery size and product makeup by volume.

b) Estimated date and time of arrival of delivery.

c) Anticipated tank space available for each product grade at the receiving oil facility.

Pre-Transfer Information Exchange

Prior to arrival of a pipeline delivery at the oil handling facility, the facility operator responsible and the pipeline carrier's dispatcher shall confirm the following as applicable:

a) Total delivery or batch volume in pipeline.

b) For multiple product batches, volume of each product, total batch volume and sequence of products in batch.

c) Estimated time of arrival of first product in batch or delivery.

d) Density or gravity of each product in batch.

e) Tank space available at facility for each product grade in batch.

f) Pipeline delivery rate and estimated total delivery time.

g) Delivery sequence.

h) Reduced delivery rates if required.

(ii) Facilities which receive oil from a transmission pipeline must:

A. Confirm that the proper manifold and valves are open and ready to receive product;

B. Notify the transmission pipeline operator when a storage tank has less than one foot of oil above the inlet nozzle;

At least one foot of cover above the inlet nozzle is intended to minimize static charge.

C. Coordinate arrival time of oil with the pipeline operator;

D. Confirm the available storage capacity for transfers to a facility;

Delivery Requirements

Just prior to the start of a pipeline delivery, the oil facility operator responsible for the transfer should:

a) Confirm that tankage space is available for the volume of each product in the delivery.

b) Confirm that the proper manifold valve and tank valve is open for the first product in the batch or delivery.

c) Confirm that pathway from manifold to first receipt tank or tanks is open.

d) Ensure that pre-delivery tank levels are taken and recorded.

e) When required, ensure that custody transfer meters are set with meter tickets in place.

f) Give consideration to documentation of key steps in the delivery process.

E. Ensure that only the designated tank(s) is (are) receiving oil.

Delivery Execution

During a transmission pipeline delivery, the oil facility operator in charge should:

a) Coordinate reduced fill rates with the pipeline operator into empty tanks or tanks with floating roofs that are resting on their legs.

b) Monitor tank levels in accordance with the operations manual and overfill protection procedures.

c) Switch receiving tanks as required.

d) For multiple product delivery batches, detect product interfaces and switch manifold valves and tank valves as required. Product interfaces may be determined by a number or combination of methods, including:

- product color
- product density
- meter countdown

Identification of Responsibilities

Timely control of oil flow during transmission pipeline transfers is critical in preventing tank overfills.

The oil facility operator and pipeline carrier should clearly establish who has control of the delivery during a transfer. Written procedures that are understood and followed are essential. Emergency operating procedures that clearly outline when the delivery must be stopped in an emergency are the key to preventing receipt tank overfills.

(iii) Ensure that proper transfer alignment of the pipeline, valves, manifolds and storage tanks have been made.

Oil Facility Receipt Manifold Design Considerations

The receipt manifold provides a means of directing oil flow from the pipeline lateral to the proper storage tank in the oil facility, by opening and closing valves. The manifold valves must be clearly identified as to product service and must provide positive line closure. Valves that can be checked for leak free operation while in service are recommended. Double block and bleed type valves may be considered for this purpose. Leaking manifold valves can lead to tank overfills and serious product contamination where multiple products are handled.

Dead legs in the piping system should be avoided to reduce corrosion. Dead legs are the unused portions of a pipeline.

The receipt manifold piping system shall meet *ANSI Standard B31.4.*

Small Discharge Containment

Valve manifolds present exposure to small oil releases due to leakage at flanges and valve packing. An effective secondary containment system should be considered to contain and collect small spills in the valve manifold area. Discharge from pressure relief devices, instrumentation connections and lines should also be contained.

Containment can be accomplished with permanently installed drip pans, concrete curbing or catch basins. Connection of the various containment components to a common sump or tank facilitates disposing of any discharge in an expedient manner. Collection sumps or tanks may be equipped with level indicators to indicate when they need to be emptied.

Prevention of small discharges should receive particular attention. An effective ongoing maintenance program will minimize small discharges.

(iv) Establish adequate communication in English between the facility and pipeline operator.

(b) For the purpose of scheduling inspections, the department may require a twenty-four hour notification to the department in advance of any transfer of bulk oil by a facility operator. The department shall request notification in writing when this procedure is required.

Ecology Inspections

Ecology may periodically wish to conduct an inspection of a facility transfer operation. The department shall request a 24-hour advance notification of a transfer when an inspection is desired.

The facility operator shall have an effective means in place to provide this notification. Notice shall include the following information:

- location of the transfer
- expected date and time of first product arrival
- type of oil being transferred

Transfer Supervision

(c) Transfer operations shall be supervised by an appropriate person.

Operator training requirements are described in *WAC 173-180C, the Facility Personnel Oil-Handling Training and Certification Rule*. Effective coordination and supervision of oil transfer operations is key to the prevention of accidental oil discharges. For manned deliveries, the oil facility operator shall appoint a person to be in charge of the operation when receiving a transfer. This person must receive adequate training for the job. Training records indicating the name of each person currently designated

as person in charge shall be maintained. For unattended remotely controlled pipeline transfers proper instrumentation is needed.

Emergency Shutdown

(d) Each facility operator shall ensure that the means of operating or requesting emergency shutdown is immediately available while oil is being transferred between the facility and the pipeline.

The oil facility operator in charge of the transfer shall immediately stop the flow of oil by closing the facility delivery valve should a tank overfill occur. The operator shall notify the pipeline carrier of his/her intention to close the delivery valve so that an orderly shutdown of the pipeline delivery lateral and/or main line can be undertaken. For unmanned remotely controlled deliveries, the person in charge of the facility delivery valve should ensure that the capability to monitor high tank levels is available to the pipeline operator so immediate action to close the valve to prevent tank overfill can be accomplished.

The oil facility operator in charge shall stop the flow of oil if tankage space is unavailable for father receipt of oil once a tank high high alarm has been activated. The operator shall immediately notify the pipeline carrier's control center of his/her intention to close the delivery valve.

The oil facility operator in charge may stop the flow of oil if there is any condition requiring immediate action to prevent a discharge or threat to personnel and public safety.

Written emergency shutdown procedures shall be on site at the oil facility. Periodic simulated testing of these procedures is recommended to ensure their adequacy and to ensure they can be effectively implemented by the oil facility operator in charge or by the person in control of the delivery valve for unmanned remotely controlled transfers.

Emergency Shut Down System

Human error and/or equipment failure may occur which can present serious oil discharges or hazard threats during transmission pipeline oil transfers. Tank overfills usually present the more serious incidents. A means of stopping oil flow in such an emergency must be provided. The pipeline terminal piping system should be designed to handle hydraulic surges generated in an emergency shutdown situation.

Manually Controlled Transfers

For manned pipeline transfers, a manually operated facility delivery valve may be employed. However, ready access to the delivery valve must be provided to ensure timely closure in the event of an emergency. Security measures are recommended to protect the valve from vandalism or unauthorized operation. The valve should be clearly identified as the facility or facility delivery valve.

For larger size delivery valves, a motor operator may be required on the valve to facilitate timely operation of the equipment. For power assisted delivery valves, a local control switch at the valve is required to open and close the valve. Remote emergency shutdown control switches located at other facility work stations should also be considered to facilitate timely closure of the delivery valve in the event of an emergency. Emergency shutdown switches should be permanently marked.

All electrical equipment including stop/start and emergency shutdown switches must meet explosion proof standards when used in hazardous areas.

To help prevent tank overfills during manned pipeline transfers, ground level tank gage readouts are recommended to facilitate tank level monitoring. Continuous monitoring of tank levels during transfers is the key in preventing tank overfills.

Means of communications must be provided to ensure tank level information is provided to the person in charge of the facility delivery, during the entire transfer operation.

Remotely Controlled Transfers

For unmanned transmission pipeline transfers, a remote controlled facility delivery valve must be used. The valve must be motor operated and controlled by a supervisory control system that is continuously on line and monitored. The control system may be operated by the transmission pipeline carrier or receiving oil facility operator. The pipeline carrier may have a supervisory control and data acquisition (SCADA) system that will control the delivery valve and provide status information. Consideration should be given to providing automatic closure of the facility delivery valve when a tank high-high alarm level is actuated.

(e) If startup, shutdown, and/or emergency shutdown are controlled by the pipeline operator directly using instrumentation and control devices, the accuracy of these devices shall checked at least annually.

(f) All transfer operations shall be conducted in accordance with operations manuals approved under chapter 173-180B WAC.

(2) Oil spills.

(a) Any person conducting an oil transfer shall stop the transfer operation whenever oil from any source associated with the transfer is spilled into the water or upon the adjoining shoreline in the transfer area.

(b) Transfer operations may not resume after a spill until:

(i) The proper notification has been made in accordance with RCW 90.56.280; and

(ii) All threats to waters of the state and public health no longer exist as determined by the appropriate person.

(c) The department may require that transfer operations stopped under subsection (2)(a) of this section may not resume unless authorized by the department.

(3) Suspension of transfer operations for immediate threat

(a) The director may order a facility to suspend transfer operations if there is a condition requiring immediate action to prevent the discharge or threat of discharge of oil or to protect the public health and safety, and the environment.

(b) An order of suspension may be made effective immediately.

(c) An order of suspension shall specify each condition requiring immediate action in writing.

(d) The transfer operation shall remain suspended until the director has determined that the need for immediate action is no

longer necessary and has notified the facility operator of that determination.

(e) The director shall notify the facility operator as soon as possible of the determination that the need for immediate action is no longer necessary.

(f) The facility operator may petition the pollution control board, in writing or in any other manner, to reconsider an order of suspension.

GENERAL CONSIDERATIONS

Over Pressure Protection

Over pressure of the oil facility piping system may result in equipment damage and lead to accidental oil discharges. The piping system and equipment shall be protected from over pressure by the transmission pipeline or from the thermal pressure when inactive, by use of engineered pressure relief systems.

Small discharges from pressure relief valves and devices shall be contained

Large discharges from the pressure relief system may occur during abnormal pipeline transfer operations (pumping against a closed valve or emergency shutdown of the system). A pressure relief discharge tank should be considered to handle the worst case discharge volume. Each transfer system will usually require specific engineering for relief tank design. The design of pressure relief should be coordinated between the pipeline and facility to prevent competing systems. A flow alarm on the relief valve discharge line should be considered to alert operators to an abnormal operating condition.

The over pressure relief tank shall meet the requirements of chapter 8 and 9.

Chapter 8

WAC 173-180A-080 SECONDARY CONTAINMENT FOR ABOVEGROUND STORAGE TANKS

The Facility Operations and Design Standards Rule requires owners to provide secondary containment areas for oil storage tankage. Essentially, this requires the construction of some form of walled basin which surrounds the tank or tanks. The purpose is to catch and confine potential leakage from the storage tanks to their immediate area or alternatively drain it to a remote impounding basin. This reduces the danger of fire and environmental damage. The walls surrounding the tanks or remote impounding basin are known as "dikes" or "berms".

(1) Aboveground oil storage tanks must be located within secondary containment areas. Secondary containment systems must be:

(a) Designed, constructed, maintained and operated to prevent discharged oil from entering waters of the state at any time during use of the tank system;

Construction and Design

There are several options for the design of a good secondary containment system. They can range from simple steel, masonry or reinforced concrete walls around smaller tanks (or those located where space is limited), to the more common compacted earth dikes. Dikes constructed of masonry are not recommended due to the porous nature of brick and the potential for cracking. If correctly designed for hydraulic loading, frost heave, properly sealed joints, etc., poured concrete dikes can provide effective secondary containment. However, cost becomes the limiting factor with increase in size.

In general, the design of secondary containment basins should be based on a site-specific assessment of variables such as:

- Site topography and subsoil characteristics;
- tank farm drainage and pattern control method;
- layout of supporting facilities and vehicular access;
- the environmental sensitivity of neighboring lands;
- seismic factor, and
- properties of the fluids in the containment system.

Required Site Modifications

Secondary containment systems must be designed, constructed and operated to prevent discharged oil from entering waters of the state. Groundwater is a water of the state. Evaluating the adequacy of existing secondary containment systems requires that the relationship between and effects of hydrocarbon on permeability be considered. Some methods to evaluate the adequacy of secondary containment systems include past experiences, observation, site testing and modeling. The information in appendix O provides insight into permeability issues. Where the native soil permeability is unsuitable for construction of the diked area, additional methods must be employed to modify site conditions to reduce percolation rates of liquids through the floors and berms of the basin. The engineering designers may consider one of the following options that meet sound engineering practices:

a) Construct the berm with native material to appropriate lines and grades. The containment basin, i.e., both the floors and walls, should then be lined with impervious cohesive clay material. Thickness may vary and will depend on the permeability of the clay and the latter should be determined by qualified engineer. Note: it is important that the impermeable layer of clay on the dike wall is continuous with, or properly keyed to a similarly impermeable layer on the floor of the contained area. The clay should be provided with suitable covering materials to prevent drying, shrinkage and erosion.

b) Sometimes it is possible to add binding agents to native soils which will reduce their permeability. Type of soil and binding agent will determine the thickness required. For example, sandy sites can be modified by mixing the sand with Bentonite (a type of clay soil) and water, and then compacting the mixture. The mixing is done with scarifying equipment.

c) The use of synthetic geomembrane liners should be considered for the basin. Material selection has to be carefully undertaken to ensure that the liner is of sufficient strength to withstand installation stresses from earth-moving equipment and also is inert to all fluids it may be in contact with. These liners are usually covered to stabilize and protect them from ultraviolet ray degradation. Note also that special sealing procedures may have to be developed with the manufacturer if any penetrations of the liner are necessary (drain lines entering through the berm, for example). Table 8.1 identifies installation considerations for dikefield secondary containment liners for several types of liners. Table 8.2 identifies failure modes and preventative measures for certain liner types.

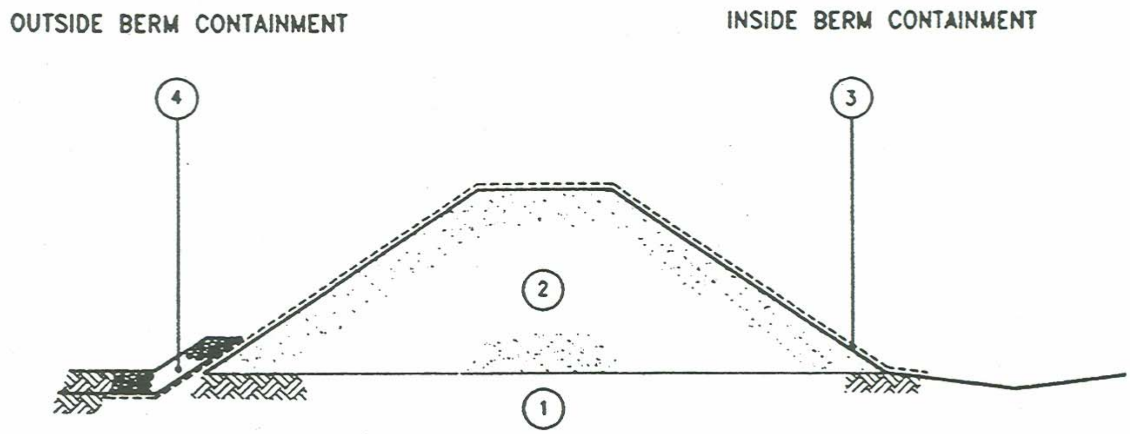
Figures 8.1 to 8.4 show several variations in the design for earthen dikes as mentioned above.

Table 8.1: Installation Considerations for Dikefield Secondary Containment				
Liner Type	**Seaming**	**Attachment to Ringwall or Tank Chime**	**Attachment to Pipes and Other Appurtenances**	**Cover**
Unsupported sheet geomembrane: High density polyethylene	Field seamed: extrusion or hot wedge method.	Retrofit: attached via compression seal with batten strip and anchor bolts. New construction: liner panel welded to HDPE attachment strip cast into wall.	Liner panels seamed to pre-formed HDPE boots and attached via compression gasket.	Cover optional with carbon-black stabilized liner; some manufactures recommended soil cover for protection.
Supported sheet or coated fabric geomembrane: Polyurethane; polymer alloys; others with proprietary trade names.	Pre-cut panels may be factory or field seamed using thermal methods. Closures may be used for field assembly of factory-seamed panels.	Mechanical attachment via batten strips and anchor bolts.	Mechanical attachment via pipe boots, sleeves, and compression gaskets.	Sand or gravel ballast recommended, 6-18" depth over installed liner to prevent ballooning.
Geosynthetic/ clay composites	Panels are overlapped a minimum of 6" or as recommended by manufacturer. Seal produced by saturation and swelling of bentonite. No seaming required.	Bead of granular bentonite placed below edges of panel. Panel lapped 4" -6" against concrete slab.	Bentonite mastic or granular bentonite troweled or poured around appurtenances	Cover required; minimum 6" depth or as recommended by manufacturer.
Sprayable Coatings Polysulfile Polyurethane	Overlapping geotextile substrates do not require seaming; coating is continuous. 4" overlap recommended. Second geotextile underlayment used for protection.	Continuous coating applied over printed concrete or metal surface. Precoated fabric placed around exterior circumference and adhered to concrete and edge of liner panel.	Precoated fabric skirt wrapped around primed pipe and adhered to liner panel. continuous coating applied over primed surfaces.	Not recommended. Cost access walkways may be placed over installed liner for tank access and liner protection.

Table 8.2: Summary of Failure Modes and Preventive Measures for Different Liner Types		
Liner Type	**Failure Modes**	**Preventive Measures**
High density polyethylene	Environmental stress cracking	Avoid installation configuration that apply tensile load across seams
	Thermal expansion and contraction; failure due to contraction in cold weather	Follow manufacturer's recommendations for installation temperature and degree of tautness
	Seam separation	Rigorous construction quality assurance at installation
	Tearing or puncture	Use extreme care. Avoid scratching or gouging liner during and after installation; limit access and inspect frequently
Supported films, coated fabrics	Billowing, liner movement	Use aggregate or backfill for ballast
	Weathering; UV degradation of exposed liner panels	Cover all exposed liner; select premium, UV-resistant grades if exposure cannot be prevented
	Separation of field-assembled panel closures	Inspect frequently; seal per manufacturer's recommendations
	Chemical-induced degradation; loss of physical properties due to petroleum exposure	Verify that liner selected is resistant to contained liquids
	Fungal or biological deterioration	Select premium liner grades compounded for resistance
Sprayable coatings	Inadequate coating thickness; leakage	Construction quality assurance; frequent checks of coating buildup during application
	Failure to cure	Strictly follow instructions for mixing and proper application; use qualified installer
	Damage due to equipment access	Use cast plastic walkways for access within containment area
Geosynthetic/clay composites	High permeability due to inadequate bentonite moisture content	Do not use in arid regions; ensure that installed, covered liner will remain saturated
	Loss of bentonite hydration and swelling capability due to reaction with fill cover	Use only fill materials that do not contain calcium.

Table 8.1 and 8.2 are taken from API publication 315 'Assessment of Tankfield Dike Lining Material and Methods' and are reprinted courtesy of the American Petroleum Institute, Washington D.C.

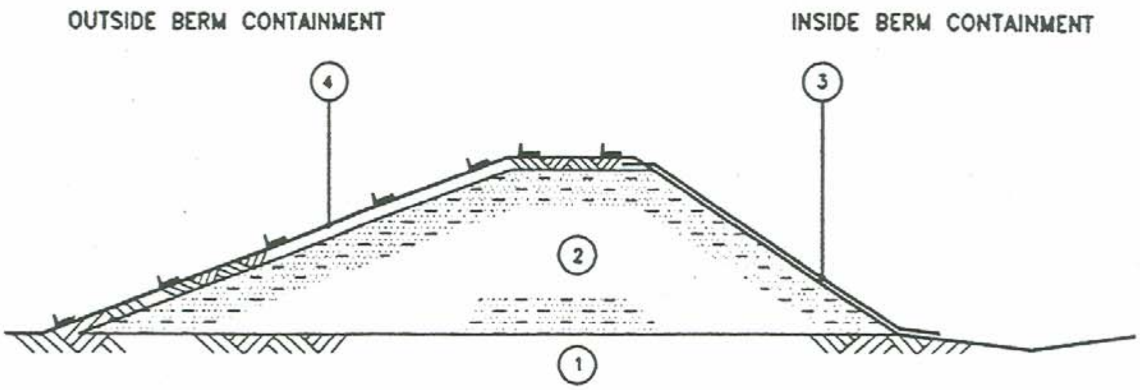
Basic Containment Berm



1. EXISTING IMPERVIOUS SUBGRADE, PROOF-ROLLED SCARIFIED AND COMPACTED.
2. IMPERVIOUS COHESIVE SOIL FILL (CLAY).
3. SURFACE COATING:
   a) SPRAY-ON ASPHALT SEALER,
   b) SELECT GRAVEL OR CRUSHED ROCK.
4. RIP-RAP WHERE TOE OF BERM FORMS DRAINAGE CHANNEL.

Figure 8.1

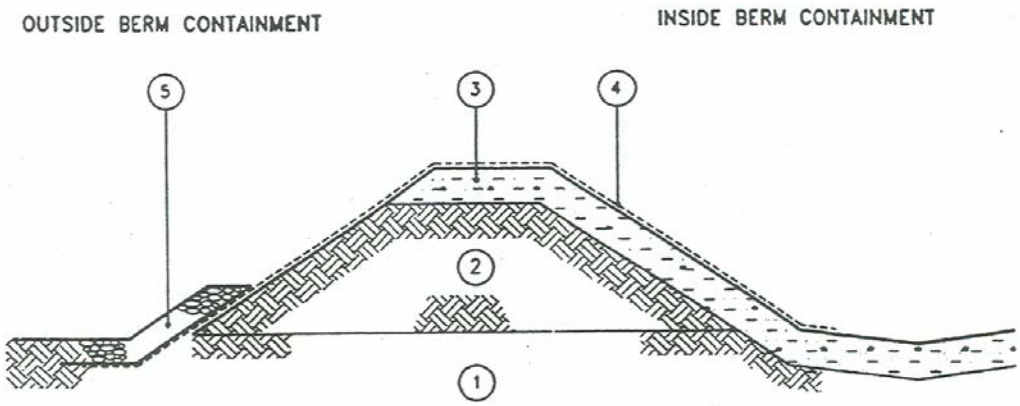
Containment Berm With Grass Surface



1. EXISTING IMPERVIOUS SUBGRADE, PROOF-ROLLED, COMPACTED, AND SCARIFIED.
2. IMPERVIOUS COHESIVE SOIL FILL (CLAY).
3. SURFACE COATING:
   a) SPRAY-ON ASPHALT SEALER,
   b) SELECT GRAVEL OR CRUSHED ROCK.
4. GRASS SURFACE ON TOP SOIL.

Figure 8.2

Containment Berm With Impervious Clay Liner



(1) EXISTING SUBGRADE, PROOF-ROLLED, COMPACTED AND SCARIFIED.

(2) NATIVE SOIL FILL.

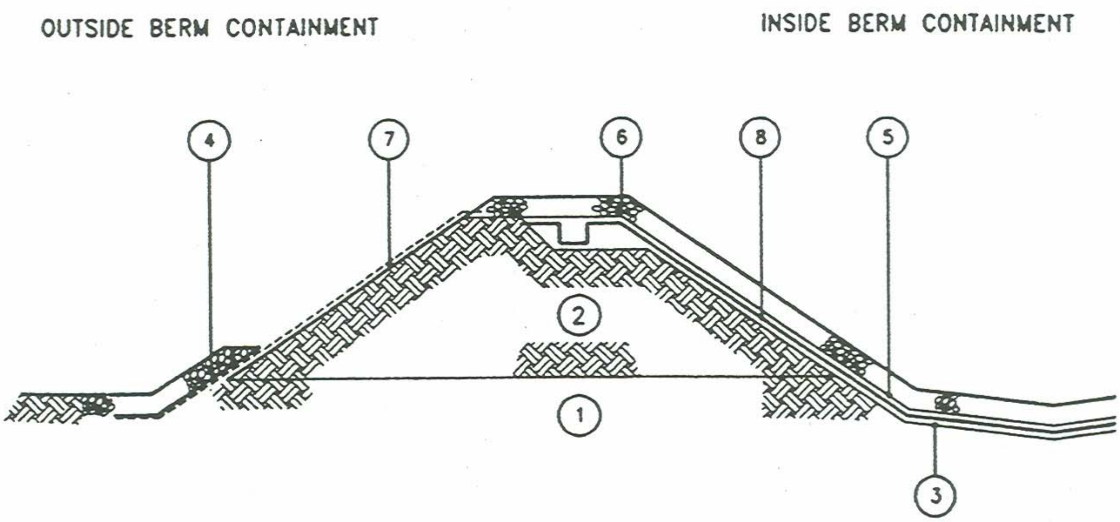
(3) IMPERVIOUS CLAY LINER.

(4) SURFACE COATING:
a) SPRAY-ON ASPHALT SEALER,
b) SELECTED GRAVEL OR CRUSHED ROCK.

(5) RIP-RAP WHERE TOE OF BERM FORMS DRAINAGE CHANNEL.

Figure 8.3

Containment Berm With Synthethic Geomembrane Liner



1. EXISTING IMPERVIOUS SUBGRADE, PROOF-ROLLED SCARIFIED AND COMPACTED.
2. NATIVE SOIL FILL.
3. 2" MINIMUM THICKNESS SAND BEDDING.
4. RIP-RAP WHERE TOE OF BERM FORMS DRAINAGE CHANNEL.
5. SAND PADDING.
6. SELECT GRAVEL.
7. SURFACE COATING:
   a) SPRAY-ON ASPHALT SEALER.
   b) SELECT GRAVEL OR CRUSHED ROCK.
8. SYNTHETIC GEOMEMBRANE LINER: MATERIAL AND THICKNESS AS RECOMMENDED BY MANUFACTURER.

Figure 8.4

Slope and Erosion Protection

The angle of the side slopes to be used in the construction of containment berms should be a function of the type of soil and should be determined by the geotechnical investigation. Shallow slopes may be used for aesthetic and maintenance reasons, such as installation of grass on the visible sides of the tank farm. (See Figure 8.2). The ability to use grass for slope stabilization may be dependent on the decision of the local fire authority or insurance adjuster.

The side slopes may be protected from erosion by one of the following methods:

- Select gravel or crushed rock;
- spray-on asphaltic surface sealer, or
- grass or vegetation subject to fire marshall approval.

Regulatory Environmental Considerations

In addition to the geotechnical investigations, the facility owner should be aware of local, state and federal environmental regulations as well as building and fire codes which may be applicable.

Site Preparation

The following is a summary of guidelines or considerations for site preparation of secondary containment systems. The area to be occupied by diked basins should be cleared of all brush, vegetative growth, fallen timber, and rubbish. Any existing structures, foundations, underground lines, and buried conduits should also be removed and disposed of, or relocated. Grubbing should include, the excavation and complete removal and disposal of tree stumps and roots, boulders, and rubbish to a minimum depth of approximately two feet below finished grade, and not less then one foot below original ground surface. Removal and disposal of grubbed materials shall be in accordance with local bylaws. Stripping should include the removal and stockpiling of organic topsoil in designated areas. Stripping should be done to such a depth as to prevent contamination with non-organic subsoil. Site grading should then proceed and should include all excavating and backfilling requirements needed to bring the secondary containment areas to lines, grades, elevations, and dimensions, as defined by the site grading design plan. The floor of the basin, (including the area directly under the dikes), should be constructed by proof-rolling, (to determine the presence of any local soft spots), scarifying and compacting the existing subgrade soils. Dike walls should be constructed in a similar manner by evenly spreading and compacting successive layers of native or imported soils free from rocks and gravel as per design specifications. Appropriate impervious liners such as clay or synthetic geomembrane should then be installed, if required, in accordance with design specifications.

Inspection and Testing

All testing of soil materials and compaction should be by a qualified person. Design specifications may require that compaction tests be made for each lift Testing should be in accordance with a recognized test procedure such as *ASTM D1557-91*.

Capacity

(b) Capable of containing one hundred percent of the capacity of the largest storage tank within the secondary containment area;

For secondary containment systems installed around new tanks, the rule specifies adherence to *Section 2-3.3 in NFPA 30*. Specifically, the volumetric capacity of the diked area shall not be less than the greatest amount of liquid that can be released from the largest tank within the diked area, assuming a full tank. *Federal SPCC* rules require a safety margin to take into account some accumulated storm/rainwater, snow and the long term effects of dike settlement and erosion. Good design practice should account for local rainfall, usually the maximum amount expected in a 48-hour period, and a 20-minute discharge from the fire protection systems, such as monitor nozzles, which flow into the basin, (The latter is required by the *Uniform Fire Code*). The designers should also check to ensure that the site does not drain adjacent lands.

Double walled storage tanks are currently allowed but not recommended for use since these tanks may not allow for an examination of the exterior of the internal tank. Also, many of the valves and appurtenances normally in secondary containment are located on the outside uncontained in a double walled tank system. The Department may reverse its opinion on these tanks as experience with double walled tank performance is gained. Also, the containment system must comply with applicable fire codes.

(c) Constructed with materials that are compatible with stored material to be placed in the tank system.

(d) Soil may be used for the secondary containment system, provided that any spill onto the soil will be sufficiently contained, readily recoverable and will be managed in accordance with the provisions under WAC 173 303-145 as amended in December 1993, spills and discharges and any other applicable regulation.

The rule specifically states that, where soil is used as the secondary containment system, it will be of such character to sufficiently contain any spilled oil so that the oil can be recovered and managed in accordance with the provisions of *WAC 173-303-145* (or other applicable regulations). *WAC 173-303-145* outlines the actions to be taken in the event of a spill such as;

- Designation of person responsible
- Notification of proper authorities, emergency, government, fire, etc.
- Incident recording
- Controlling and containment of the leak
- Clean-up, treatment of contaminated water, soil, etc.,
- Restoration of the environment

Soil permeability to water and oil is therefore a crucial consideration in the proper design of secondary containment systems constructed from soil materials.

Containment Strength

(e) Constructed with sufficient strength and thickness to prevent failure owing to pressure gradients (including static head and external hydrological forces), physical contact with the fluid stored in the storage tank, climatic conditions, and the stresses of daily operations (including stresses from nearby vehicular traffic);

The design of dikes shall ensure that they are suitable for the ambient temperature, hydraulic and other environmental and working stresses expected to be encountered. The dikes and floors of the containment basin should be liquid tight and constructed with materials which are compatible with the oil stored in the tanks.

(f) Placed on a base or foundation capable of providing support to the secondary containment system, resistance to pressure gradients above and below the system, and capable of preventing failure due to settlement, compression or uplift;

Tanks and their secondary containment basins must be constructed on sites which are suitable for both the weight of the tanks and the load stresses which will potentially be imposed by a full head of water within the diked area.

(g) Sloped or otherwise. designed or operated to drain and remove liquids resulting from leaks, spills, or precipitation. Spilled or leaked oil and accumulated precipitation must be removed from the secondary containment system in a manner which will provide the best achievable protection of public health and the environment; and

Diked areas shall be graded towards an established low point at a minimum one percent slope to allow for the efficient collection and removal of accumulated precipitation and oil leaks. *NFPA 30* requires a slope of not less than 1 % away from a tank for a distance of at least 50 fed to the dike wall, whichever is less. The grading should direct the liquid from a potential leak in the tank(s) or piping to an area within the basin that is remote from the tank(s) and piping.

Inspection

(h) Visually inspected monthly to confirm secondary containment integrity. Items requiring attention as determined by the visual inspection must be documented. Records must be kept on site for a minimum of three years.

Regular physical inspections are an important part of oil leak detection and mitigation in spill containment areas. Nearly all small and medium size facilities use visual inspection to detect leaks and to check for contamination of storm water.

Concrete dikes should be inspected monthly for and should be repaired promptly.

Note that the rule requires that the containment basins be inspected monthly to confirm integrity, observations documented and records kept for three years minimum.

Section 5-5.3 "Inspection and Maintenance" of NFPA 30 covers the following:

- Fire protection equipment.
- Flammable liquids handling.
- Storage and disposal of combustible waste material and residues.
- Housekeeping around facilities where (flammable) liquids are stored, handled or used.
- Operating and emergency route accessibility.

Table 8.3 is a checklist of items that may be included in the inspection. See Appendix K for a suggested format for optional inspection procedures.

TABLE 8.3

MONTHLY INSPECTION CHECKLIST

- Presence and/or volume of oil/water in the containment area
- Soil or dike lining color changes; noticeable sheen on water puddles
- Presence of hydrocarbon odors in the containment area
- Visual checks of tanks, pumps, valves, and flanged and threaded piping connections
- Storage tank overflowing
- Operation of tank level controls and overfill protection equipment
- Operation of sump or aboveground oil/water interface detectors (if installed)
- Recording of accumulated liquids contained in area (i.e., uncontaminated storm water, contaminated runoff or pure product) for follow-up action

Note: In the course of their inspections for signs of leaks, operators should also be watching for signs of dice erosion, inoperable equipment (such as the drain valves and fire monitors), personnel hazards that need repair, condition of personal protective equipment for use in an emergency, etc.

Maintenance

(2) The secondary containment system must be maintained to prevent a breach of the dike by controlling burrowing animals and weeds;

Erosion is the principal concern with earthen dikes, particularly in regions subject to heavy rainstorms. A regular program to inspect for erosion and to repair any eroded area is recommended. The grassed slopes on dikes should be properly maintained to control both grass height and weeds, since dried weeds and grass present a serious fire hazard. Weed control will also make it easier to find and repair the burrows of ground dwelling animals. The latter can cause serious damage to the internal structure of the berms. Deep rooting weeds can also penetrate the impervious lining of the dike.

(3) The secondary containment system must be maintained free of debris and other materials which may interfere with the effectiveness of the system, including excessive accumulated precipitation.

The Rule specifies that secondary containment areas must be kept free of debris. *NFPA 30* also prohibits the storage of combustible materials within the diked area. The concern is loose debris could potentially plug off or interfere with the drainage system or create an additional hazard in the event of a fire. Therefore, the basin enclosed by the dikes should not be used for storage of barrels, tools, equipment or refuse.

The Rule stipulates special requirements and precautions shall be taken when releasing water accumulations from secondary containment areas to "land or waters of the state."

The Rule calls for the removal of accumulated precipitation and spilled or leaked oil from the secondary containment systems in a timely manner, to mitigate air and water pollution. In an emergency situation, the full capacity of the diked enclosure is available to contain a spill, or in the event of a tank or diked area fire, to contain the fire water from monitor nozzles and other fire-fighting equipment.

(4) The facility shall maintain at least one hundred percent of the working capacity of the largest storage tank within the secondary containment area at all times.

This requirement is intended to ensure that the secondary containment holding capacity is adequate during all construction within a secondary containment area. For example, there may be instances where a secondary containment dike may be cut to allow for maintenance of piping or construction. Under these conditions the capacity of the storage tanks within the containment area would have to be adjusted to the holding capacity of the breached dike.

(5) All secondary containment pumps, siphons and valves must be properly maintained and kept in good working order.

Valve Operation

(6) Drainage of water accumulations from secondary containment areas that discharge directly to the land or waters of the state must be controlled by locally operated, positive shutoff valves or other positive means to prevent a discharge. Valves must be kept closed except when the discharge from the containment system is in compliance with chapter 90.48 RCW, Water pollution control. Valves must be locked closed when the facility is unattended. Necessary measures shall be taken to ensure secondary containment valves are protected from inadvertent opening or vandalism. There shall be some means of readily determining valve status by facility personnel such as a rising stem valve or position indicator.

An unavoidable problem with diking systems is ongoing rainwater and snow melt accumulation inside the dikes. In the event of an oil leak, the problem is compounded because this water may require treatment to remove the oil before the water is released back into the environment. To pipe the water back out of the containment basin requires the installation of a drainage system, either by gravity or pump/siphon arrangement. The drainage system design shall include means by which any oil contamination can be efficiently removed from the water before the latter is released back into the environment.

Some mechanical means may be provided to permit the periodic removal of accumulated water from the containment area. One way is by a pipe, (properly protected from corrosion), placed at the low point of the containment area to drain the water through the containment berm. See Figure 8.5. Gradient of the pipe should be a minimum of 1%. A steel isolation valve may be installed on the drain pipe, outside the diked area, to contain and control the release of fluids. The valve must be capable of withstanding the pressure of a fill head of water in the dike basin. The use of steel valves ensures isolation integrity in the event of a fire within the diked area.

A second means of water removal from the diked area is to install a pump and piping over the dike walls as depicted in Figure 8.6. This method avoids the necessity of piercing the dike with the drain and also affords additional protection in case the drain valve is accidentally left open. Siphoning the water (or oily water) over the dike wall is another technique illustrated in Figure 8.7. This requires an elevation differential to ensure the siphon action works efficiently. Some mean's of initiating the liquid flow is also required, such as the small vacuum pump shown.

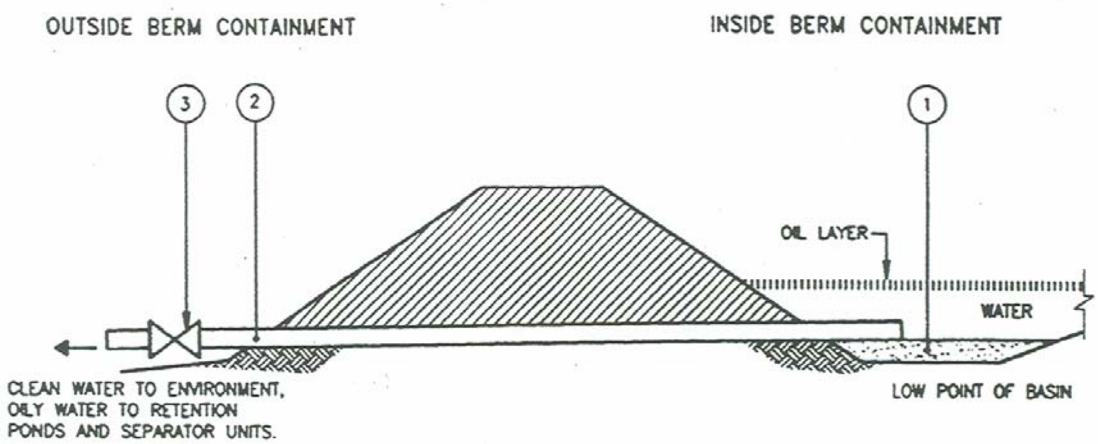
Advantages of a siphon arrangement include:

- No through-dike piping, thus eliminating a potential leak source from inside to outside of the dike.
- The siphon is essentially fail-safe. It requires operator action to start the siphon. Flow stops automatically once the collection sump is empty, (loss of flow in a pump drain system could result in damage to the pump internals if it runs dry). Note that flow can also be stopped at any time during the transfer by opening the vacuum breaker valve or dosing the drain valves.
- Cost of a siphon system is low, especially if a manually-operated vacuum pump is used to prime the system.

The storm water removal system requires periodic inspection for signs of malfunctioning. Valves associated with the drainage lines should be checked to make sure that they are dosed, locked and not leaking. Any pumps or siphoning equipment associated with the secondary containment system should also undergo routine maintenance to ensure that they are continuously reliable, especially under emergency conditions.

Drains from containment areas must be provided with positive shutoff valves or other positive means, to prevent a discharge. These are to be easily accessible from outside of the dike especially in the event of a fire, and kept closed when not in use. Only when the water quality in the containment area is in compliance with *Regulation 90.48 RCW* may these valves be opened to waters of the State. The regulation makes it an unlawful act to discharge "oil" into the "waters of the State" and defines "oil" as any petroleum related product, such as gasoline, crude oil or lubricating oil. The owner/operator may, after inspecting the water and verifying that no oil will be discharged with the water to the environment, proceed to open the valve provided that the operator comply with *90.48 RCW*. These valves must be kept in a locked closed position at all times when the facility is unattended. They must be protected from inadvertent opening or vandalism and their open/closed status must be readily determined by facility personnel. Protection from vandalism can be achieved through securely fenced enclosures, chaining/padlocking, TV camera surveillance, etc. In addition, valves should be provided with some means of positive indication of operating position, i.e., open or closed, such as labeling or a rising stem, which is immediately visible to operators. Facility operating procedures and employee training will also help to ensure mistakes are minimized.

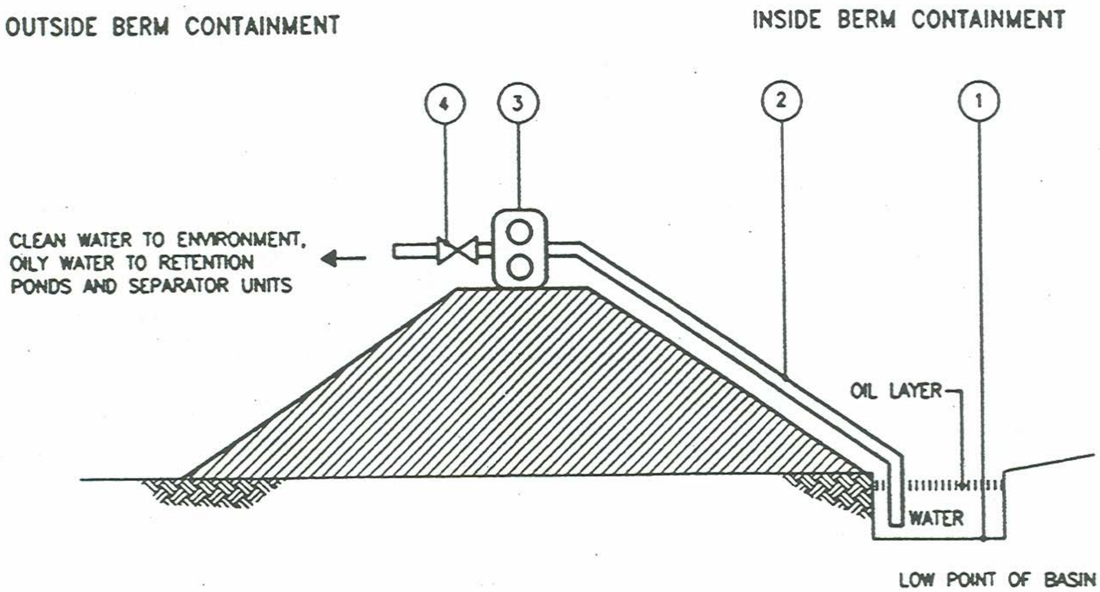
Drainage Option No. 1
Gravity Drain



1. WASHED ROCK ARMOR.
2. STEEL DRAIN PIPE, CORROSION PROTECTED AND PROVIDED WITH APPROPRIATE SEALS TO MAINTAIN IMPERMEABILITY OF DIKE WALL.
3. STEEL VALVE(S), FREEZE PROOF, IN NORMALLY CLOSED AND LOCKED POSITION.

Figure 8.5

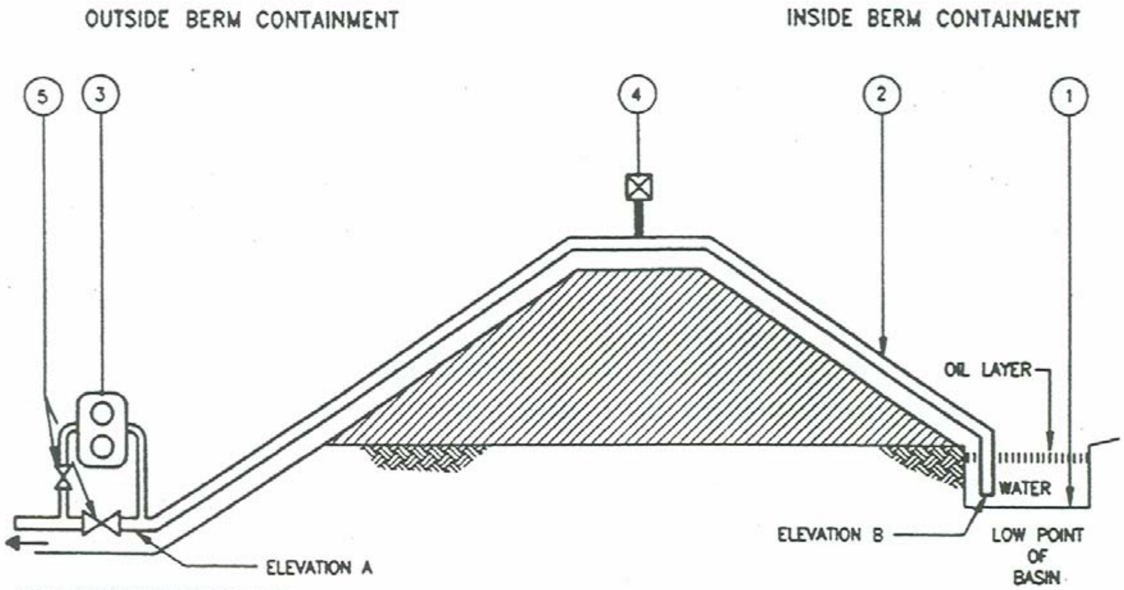
Drainage Option No. 2
Pump Over Dike



1. IMPERVIOUS SUMP TO COLLECT PRECIPITATION RUNOFF AND POTENTIAL OIL LEAKS AND SPILLS.
2. PUMP SUCTION LINE, THERMALLY TRACED AND INSULATED.
3. POSITIVE DISPLACEMENT PUMP, THERMALLY TRACED AND INSULATED.
4. STEEL VALVE, FREEZE PROOF, IN NORMALLY CLOSED AND LOCKED POSITION.

Figure 8.6

Drainage Option No. 3
Siphon Over Dike



1. IMPERVIOUS SUMP TO COLLECT PRECIPITATION RUNOFF AND POTENTIAL OIL LEAKS AND SPILLS.
2. SIPHON SUCTION LINE, THERMALLY TRACED AND INSULATED, IF NECESSARY.
3. SMALL VACUUM PUMP, THERMALLY TRACED AND INSULATED, IF NECESSARY.
4. HIGH-POINT VACUUM BREAKER, (VENT VALVE).
5. PRIMING VALVES.

NOTE: ELEVATION A IS LOWER THAN ELEVATION B.

Figure 8.7

Containment System Discharge

(7) The owner or operator shall inspect or monitor accumulated water before discharging from secondary containment to ensure that no oil will be discharged to the waters of the state. All water discharges shall comply with state water quality program regulations as described in chapter 9048 RCW.

The secondary containment basin water can occasionally become contaminated with oil from pipe or tankage leaks. Therefore, the drain system shall have provision to collect oily water and skim it locally and/or direct it to treatment facilities such as retention ponds and oil/water separators. Refer to *"Design Criteria for Gravity Oil/Water Separators" Ecology publication no. 82-1 or "Stormwater Management Manual for the Puget Sound Basin (Technical Mcnrual) " publication no. 91-75* for oil/water separator design criteria.

(8) The department may require oil containers less than ten thousand gallons (two hundred thirty-eight barrels) capacity to have secondary containment when the container is located less than six hundred feet from navigable waters of the state or a storm water or surface drains which may directly impact navigable waters of the state.

All oil containers capable of impacting navigable waters of the State should have effective secondary containment. However it may not be practical for smaller storage tanks to be subject to an API 653 inspection. For this reason, a tank capacity limitation was inserted in the definition of storage tank. This requirement is intended to address the gap between the storage tank definition and the belief that all oil containers capable of impacting navigable waters of the State in event of a release should be properly contained.

New Secondary Containment Systems

(9) A secondary containment system constructed after the adoption date of this rule shall be installed as follows:

(a) In accordance with the 1993 version of the National Fire Protection Association (NFPA), Flammable and Combustible Code, No. 30, section 2-3.4.3;

National Fire Protection Association and Uniform Fire Code

Mandatory rules for the control of spillage from above ground tanks are covered in NFPA 30 (1990) Code "Flammable and Combustible Liquids." These rules shall be followed, wherever applicable, in the design and construction of any new secondary containment system for oil storage tanks. The following is a brief description of the topics covered under this code;

a) Remote impounding - drainage to remote impounding areas, drain slopes, capacity, routing, distance from property lines.

b) Impounding around tanks by diking - slope away from tank, volumetric capacity, property line setbacks, dike materials, slopes, porosity requirements, height restrictions, operating access, penetrations by piping; minimum distances between tank and toe of dike, subdivision of impounding dikes by intermediate dikes or drainage channels, control of water drainage from diked areas and storage of combustible materials.

(NFPA also contains rules on the design and construction of tanks, their locations with respect to property lines, public ways and buildings, also spacing between adjacent tanks. The reader is referred to Chapter 9 "Storage Tanks", for more details on these aspects of design).

UFC Standard

Ecology adopted NFPA 30 because this standard offered greater protection than the Uniform Fire Code for secondary containment systems. It should be noted that the State fire marshal has adopted the Uniform Fire Code. It is suggested that both codes be reviewed prior to designing a secondary containment system since the facility is required to comply with both codes. The facility should also be cognizant of local fire codes which may apply to the facility.

Appendix E provides a comparison of NFPA 30 and Uniform fire Code(UFC) requirements. The NFPA 30 Standard and the UFC are essentially the same with regard to tank spacing and secondary containment requirements, with the following exceptions:

Remote Impounding

NFPA 30 requires a minimum distance of 50 feet between the liquid level of the impounding basin, when filled to capacity, and any tank or property line that can be built upon.

UFC requires impounding basins to be designed to retain a spill from the largest tank in the basin plus the required fire flow for a 20-minute discharge from automatic protection systems such as monitor nozzles.

Tank Impounding

NFPA 30 stipulates that the basin requires a slope of not less than one percent away from the tank for at least 50 feet or to the dike base, whichever is less.

NFPA 30 requires that the outside base of the dike at ground level be no closer than 10 feet to any property line that is or can be built upon, for access purposes.

There is a slight variation between one of the UFC and NFPA 30 diked area subdivision parameters. From the *NFPA 30: "When storing normally stable liquids in tanks not covered in Subsection (1)*, one subdivision for each tank in excess of 2,380 bbl", the UFC calls for 2,500 bbl.

NFPA 30 also has an additional requirement that whenever two or more tanks storing Class 1 liquids, any one of which is over 150 feet in diameter, are located in a common diked area, intermediate dikes shall be provided between adjacent tanks to hold at least 10 percent of the capacity of the tank so enclosed, not including the volume displaced by the tank.

(b) Secondary containment systems must be capable of containing one hundred percent of the capacity of the largest storage tank within the secondary containment area;

(c) Secondary containment systems shall be designed to withstand seismic forces;

Seismic Concerns

Washington State is located in a seismically active area of the United States. The entire Puget Sound and the surrounding area is within seismic risk zone 3 as identified in the *Uniform Building Code (UBC)*. Eastern Washington is in zone 2b. The zoning classification indicates that the potential for relatively significant earthquakes to occur in the area exist. Earthquakes produce ground shaking, surface faulting, and vertical movement that cause direct damage to building and land. They may also cause destructive water waves such as tsunamis and seiches. The ground motion induced by earthquakes may trigger ground failures such as landslides, differential compaction of soil, and liquefaction of water-saturated deposits such as landfills, sandy soils, and river deposits.

The stress induced by earthquakes will have a significant impact on the structural integrity of oil storage tanks as well as secondary containment systems. In 1977, the API incorporated seismic design requirements for welded oil storage tanks in the sixth edition of *API Standard 650 (Appendix E)*. *The NFPA 30* has addressed some requirements for the design of diking around aboveground storage tanks (*section 2-3.43, 1993 Edition*). However, there are no established industrial standards for the seismic design of oil handling facility secondary containment system's

at this time due to the wide variety of secondary containment systems used, and site specific surface or subsurface conditions.

In order to ensure that the containment system can withstand seismic force, the following items should be properly investigated and evaluated by a qualified engineer:

1. Site surface conditions:
    - Location of the storage tanks
    - Site drainage pattern
    - Any potential geological or seismic faults
2. Site subsurface conditions:
    - Soil profile and physical properties of the subsoil
    - Ground water table
    - Allowable soil loading
    - Potential settlement of underlying soil layers
    - Soil liquefaction potential
    - Site specific earthquake ground motion
3. Design of secondary containment system

The containment system should be designed to accommodate any adverse conditions caused by the design earthquakes or in accordance with appropriate building codes. The design details of the containment system are out of the scope of this manual. Due to the complexity of issues involved in conducting a competent site seismological assessment, the department highly recommends that a qualified consultant specialized in seismic design be included in the design process.

There are a number of studies which cover the various regional seismological features of the state of Washington. The studies may provide the designer valuable information in conducting seismologic assessment for the project site. The principal repositories for regional seismic studies are:

Corps of Engineers Library in Seattle

Department of Natural Resources Library in Olympia

Regional Office of the Federal Energy Regulatory Commission in Portland

Department of Ecology Dam Safety Section

(d) Drains and other penetrations through secondary containment areas must minimized consistent with facility operational requirements; and

(e) Secondary containment systems shall be designed and constructed in accordance with sound engineering practice and in conformance with the provisions of this section.

Chapter 9

WAC 173-180A-090 STORAGE TANK REQUIREMENTS

(1) Storage tanks constructed after the adoption date of this rule shall meet or exceed the 1993 version of the National Fire Protection Association (NFPA 30) requirements and one of the following design and manufacturing standards:

> **(a) UL No. 142, Steel Aboveground Tanks for Flammable and Combustible Liquids dated April 1993;**
>
> **(b) API Standard 650, Welded Steel Tanks for Oil Storage dated November 1988;**
>
> **(c) API Standard 620, Design and Construction of Large Welded, Low-Pressure Tanks dated June 1990; or**
>
> **(d) Another standard approved by the department.**

This manual addresses the design, material, fabrication, erection, inspection, testing, operating and repair guidelines for storage tanks.

API 650 covers the design and construction of vertical cylindrical tanks of all sizes while *UL 142* covers both vertical and horizontal tanks of relatively smaller sizes (up to 1,190 barrels).

API 12D and *12F* are for vertical tanks of sizes up to 10,000 and 750 barrels respectively. The choice of codes will depend on tank size, and intended services.

NFPA 30 and *UFC* deal primarily with fire protection. The code addresses requirements of installation, spacing, spillage control, venting, diking, and secondary containment.

AS2l4E Section IX specifies welding requirements; *API 650* provides input for wind load and seismic design.

Codes and standards referenced in the above codes should be followed where applicable.

Tank Types

This is a vertical cylindrical tank with a cone or dome or umbrella roof which is either self supported off the shell or supported with one or more interior columns resting on the tank bottom plates.

This type of tank is common for low vapor pressure fluid, such as diesel oil, when the loss of fluid by vaporization into the atmosphere is not a concern.

Open Top, Floating Roof

This is a vertical cylindrical tank with a floating roof that floats on top of the tank fluid. Vapor leakage is minimized between the periphery of the float and the tank shell by means of a flexible seal. A roof drain has to be provided. This type of tank is used for higher vapor pressure fluids (such as condensate) which will readily evaporate into the atmosphere.

This type of tank will leak small amounts of vapor to the atmosphere, depending on condition of the seals. Rain and snow may also impair the operation of the float.

Cone Roof, Internal Float

This is similar to an open top floating roof except that it has a self- supporting cone or dome roof on top of the tank.

This design provides protection of the float from weather. The external fixed roof can further reduce and control the emission of vapor to the atmosphere. Where strict environmental guidelines are to be followed, a vapor recovery system can be installed to prevent the escape of vapor to the atmosphere.

Horizontal Tank

This type of tank, primarily covered by *UL 142*, is a horizontal cylindrical tank supported with saddles. It is limited to small capacities (less than 1,200 barrels) and is commonly used for storage of oil sludge and waste.

Tank Services

The design of storage tanks will depend on the chemical and physical characteristics of the fluid to be contained. In the event of change of tank service, the design should be re-evaluated and the tank inspected to ensure suitability for the new service in accordance with *API 653*.

Tank Design

Environmental Considerations

The tank location will influence tank design and construction. Factors to be considered are:

- Design wind load per *BOCA* Building Officials and Code Administration.
- Design seismic load per *API 650*, Appendix E.
- Design rainfall and snow load per *BOCA* Building Officials and Code Administration.
- Design metal temperature per *API 650*.
- Local soil conditions which will affect foundation design.
- Ground water level and flow pattern.
- Proximity to waterways.

Note that local building codes may require that structures conform to standards other that those listed above such as the Uniform Building Code.

Material Specifications

All materials for the shell, bottom, roof welding electrodes, structural components, piping, forging, bolting, welding, etc. shall comply with the applicable tank code. Normally the material specifications are indicated by the tank manufacturer in their proposal based on the service specified by the owner.

Impact testing of the steel plate may be required dependent on plate thickness, design metal temperature or owner's requirement (for sour service, etc.).

MTR (Material Test Reports) and special test reports may be required by applicable code. If required they should show:

- impact testing result

- minimum yield strength
- chemical composition and grade
- ASTM code designation (e.g., A283 Grade C) carbon equivalent
- dimensions

Shell Design

Shell Thickness

The shell thickness will depend on the tank diameter, specific gravity of the contained fluid, maximum liquid level, corrosion allowance, allowable stress depending on the materials and the joint efficiency (depending on the weld seam design). If the fluid to be stored is lighter than water, then hydrostatic (water) testing conditions shall govern the shell thickness design. For tanks designed to standards other than *API 650* the wall thicknesses are shown in the appropriate tables in the alternate codes.

Floating Roof Seal Protection

For open top tanks, the owner shall ensure that no part of the floating roof seal can, during the course of normal use, extend above the top of the shell in a manner that may cause damage to the seal. For tanks with self-supporting fixed roofs, the owner shall ensure that no part of the floating roof seal can come in contact with the fixed roof.

Bottom Design

The most frequent bottom failure is caused by internal or external corrosion. Tank bottom inspection and repair is difficult and expensive to perform because it may require the tanks be shut down, emptied of contents and gas-freed.

Slope and Center Sump

It is recommended to slope the tank bottom towards a water draw off sump. The-purpose of the sump is to accommodate removal of stagnant water and sludge (especially for crude service) from the tank bottom on a regular basis. This reduces internal tank bottom corrosion.

Plate Thickness

It is recommended that bottom plates have a corrosion allowance internal and external) above the 1/4" minimum plate thickness allowable per code requirements. Installation of an annular butt welded ring should meet the requirements of table 3-1 of API 650. The shell and bottom plate joint is subject to the highest stress and settlement conditions.

Shell to Bottom Weld

Because of the severe loading conditions at the shell to bottom seam, welding at this seam shall be continuous, minimum two pass fillet weld on each side of the shell plate. The fillet weld size shall be equal to the thickness established in API 650.

Bottom Reinforcement

In order to protect bottom plates from mechanical damage as well as from erosion, a reinforcement plate (called the striker or wear plate) of minimum 1/4" thickness may be fully (seal) welded to the bottom plate and recommended for the following:

- fill nozzle or fill pipe
- floating roof deck and vent landing legs
- gage stilling well
- mixer manways
- internal piping support legs fixed roof support columns

Double Bottom

For existing tanks that have a damaged bottom due either to corrosion or fracture caused by settlement, an acceptable method of repair is to install a new bottom over the existing bottom with the space between them filled with sand, gravel or concrete. Caution needs to be exercised to prevent the new replacement tank bottom from corroding at an accelerated rate due to trapped moisture between the two bottoms. The designer should also consider the possibility of one of the tank bottoms acting as a sacrificial anode in instances where the character of the metal and environmental conditions are conducive to that possibility. The new bottom may be cathodically protected by placing anodes between the two bottoms.

Internal Liners

Tank liners may be used to prolong the life of a tank bottom. *API Recommended Practice 652, Lining of Aboveground Petroleum Storage tank bottoms*, provides guidelines for liner and coating installation procedures and practices. Proper installation of a tank liner requires that the proper liner be selected, the tank surface be properly prepared, the liner installed properly and inspection of the completed work to ensure quality control.

Roof Design

Weak Roof to Shell Seam

For a fixed roof tank, the weak roof-to-shell seam also known as frangible joint design is recommended. In the event of a tank over pressure, this design allows for release of energy by allowing the roof seam to fail.

Venting Requirement

For a fixed roof tank, rapid filling or emptying can cause tank bucking or rupture if insufficient vent capacity is available. Venting shall be designed per *API 2000*. For covered tanks with an internal floating roof, the vents shall be located on the tank roof or above the upper travel limit of the floating roof seal.

Design Data

The roof structural design shall take into account local rainfall, snow, wind and seismic conditions. Automatic Vacuum Breaker Vent

For floating roofs, vacuum breaker vents of sufficient size shall be provided. They shall open automatically when the roof is lowered to its lowest position. In the absence of breaker vents, continued emptying of the tank with the floating roof in the lowest position may cause shell buckling and roof damage.

Shunts/Anti-Static-Arcing Protection

Shunts for removing electrical charges caused by an electrical storm shall be provided on all open top, floating roof tanks to connect the secondary seal to the roof.

For internal floating roof tanks, anti-static protection shall be provided with electrical bonding to the tank shell and floating roof. This will prevent explosions and fire caused by static electricity in an explosive atmosphere (hydrocarbon vapor in the enclosed space).

Suction and Fill Nozzles/Appurtenances

To reduce electrostatic charges in products service and to minimize erosion, it is recommended that the incoming flow velocity be kept below three feet/second. This can be accomplished by slotted suction/fill nozzles.

Piping stress loads on tank nozzles should be calculated. Expected tank settlement should be estimated and these two factors should be taken into consideration in the design of tank nozzles.

The loads, especially caused by settlement, can be minimized by designing and constructing a solid tank foundation which will minimize settlement, and provide increased flexibility in the external tank piping. Increased flexibility can be achieved by a combination of spring hanger supports and suitable bends.

Tank Anchoring

For storage tanks located in areas where there is a potential for flooding, earthquakes or high winds, anchoring the tank to the foundation should be considered. Refer to *API 650, Appendices E card F.*

Foundations for Storage Tanks and Secondary Containment Systems

The choice of a foundation system for storage tanks and the design of a secondary containment system is governed by several factors, such as: topography, soil conditions, and cost.

Geotechnical Investigations

A site investigation should be carried out under the supervision of an experienced engineer. This investigation should be carried out to serve as a basis for foundation design for tanks and also for the design of containment systems. Facilities may use existing data or site experience to support foundation design.

Each site investigation should be "site specific." That is, no reliance should be placed on general "rules of thumb" or standard designs which may not be applicable to a specific site.

Foundations for aboveground tanks

Any tank foundation design must meet certain performance requirements:

a) It must provide a stable plane for the support of the tank

b) It must limit overall settlement of the tank grade to values compatible with the allowances used in the design of connecting piping.

c) It must provide adequate drainage.

If initial investigations indicate that tank settlement would be unacceptable, additional measures may need to be taken, which may include one or more of the following:

a) Remove the objectionable material and replace it with other suitable, compacted materials.

b) Compact the soft material by preloading with an overburden of suitably drained earth or other material.

c) Compact the soft material by removal of the water content by drainage, if practical.

d) Stabilize the soft material by chemical methods or injection of cement grout.

e) Support the load on a more stable material underneath the subgrade by driving bearing piles or constructing foundation piers down to it. This will involve construction of a reinforced slab on the piles to distribute the load of the tank

f) Construct a foundation which will distribute the load over a sufficiently large area of the soft material so that the load intensity will be within allowable limits and excessive settlement will not occur.

A well designed foundation can minimize tank bottom corrosion. Following are the ideal conditions for such a foundation:

- •The pad is elevated and the diked area graded so that runoff water will not accumulate around the tank bottom, and will drain away from the tank.
- •Unsuitable sub-soil will be excavated and replaced with ailed-and well compacted sand containing no debris to form a moisture free and uniform cushion for the tank bottom.
- •A reinforced concrete ring wall can also be provided to ensure firm support for the tank shell and annular ring thereby minimizing edge settlement of the tank.

Foundation designs may be generally categorized into three basic types:

* Earth
* Earth, with crushed stone or concrete ring wall
* Concrete pad

Earth Foundations:

These are usually reserved for tanks located on stable soil. The foundation basically consists of compacted crushed stone, screenings, fine gravel, clean sand, or similar material placed directly on virgin soil. Any unstable materials must be removed and replaced with suitable material which is compacted in place.

Earth with ring wall foundations:

In situations where substantial loads will be imposed on the foundation immediately under the shell, or in any case where the ability of a foundation to carry the shell loads directly is in question, a ring wall is recommended. This ring wall may be constructed with crushed stone or reinforced concrete. The ring wall foundation provides solid support for the shell while the compacted fill provides evenly distributed support for the remainder of the tank bottom.

A ring wall foundation has several advantages to non-ring wall designs:

1) It provides better distribution of the concentrated load of the shell to produce a more nearly uniform soil loading under the tank.
2) It provides a level, solid starting plane for construction of the shell.
3) It provides a better means of leveling the tank grade and preserving its contour during construction.
4) It retains the fill under the tank bottom and prevents loss of material as a result of erosion.

API 650, Appendix B also describes the important parameters to be followed when designing either the crushed stone or reinforced concrete type of foundation. These include:

- Ring wall size and depth recommendations.
- Trueness tolerances to horizontal plane of ring wall top. (Especially important for floating roof tanks, where out-of-roundness tolerances for the shell are very tight).
- Recesses required in wall for cleanouts, drawoff sumps, etc.
- Concrete reinforcement against shrinkage, temperature and lateral forces.
- Weathering and runoff protection for crushed stone ring wall shoulder.

Construction and drainage grading

It should be noted that ring wall foundations provide adequate resistance to settlement and corrosion at reasonable cost and are the industry standard, especially in larger tank sizes. See *API 650, Appendix B* for drawing examples of two types of ring wall foundations.

Concrete Pad

These types of foundations are usually reserved for small pre-fabricated tanks, (shop-fabricated and hoisted in place at the site). The concrete pad is structurally strong and provides protection from ground moisture and corrosivity problems provided it contains proper drainage. A special version of this foundation is the piled slab foundation which uses piles driven into the subsoil to support the slab in areas where the subsoil lacks the required bearing strength. This is one of the most expensive types of foundation.

The concrete tank foundation can also perform as leak detection by constructing radial groves on the floor slab which is sloped to the outside edge of the foundation. The concrete slab should be designed in accordance with American Concrete Institute standard 350 to ensure for leak tightness. This foundation design is described in *API 650* appendix I.

Inspection, Testing, Quality Control

An inspector familiar with *API 650* or other applicable code should be engaged by the owner to ensure compliance with applicable codes, standards, and regulations. Following is a list of items which should be reviewed.

Tank Design Data and Calculations

- codes and their compliance services
- environmental
- material specifications
- shell thickness & joint design
- bottom design & joint design
- roof design
- tank appurtenances

Tank Construction

The tank contractor should have adequate fabrication and erection plans and procedures in place.

All documentation should be available; i.e., Material Test Reports (MTR), all NDE records (x-rays and vacuum test records on the bottom, hydrostatic test records, etc.), all welding procedures and their qualification reports, tank settlement records of shell and bottom, etc.

Other Considerations

- cathodic protection method(s) tank bottom lining
- tank foundation design
- tank overfill protection
- leak detection method(s)
- lightning protection
- secondary containment design
- fire protection scheme
- tank spacing requirements from *NFPA 30 and UFC*
- tank operating and inspection procedures
- routine visual inspection
- formal in-service inspection
- scheduled shutdown inspection
- tank filling and emptying
- monitoring of tank corrosion

Tank Shell Testing

The shell of newly constructed atmospheric welded steel tanks for oil storage shall be tested for leaks before connection to the facility piping system. If sufficient water is available, the tank shall be filled with water for testing. If water is not available, shell joints may be tested by vacuum or air pressure or penetrating oil or any combination of these methods. Specific procedures are found in API Standard 650 Section 5.3 "Inspection, Testing and repair for tank bottom, shell, roof and reinforcement plate joint testing". Disposal of test water shall be consistent with the provisions of 90.48 RCW, Water Quality Control.

Tank Volume Calibration

Accurate tank calibration tables are essential for proper oil storage inventory management and available tank space determinations. Both of these matters have safety and on spill implications.

It is recommended that tank calibration (tank strapping) be completed before the installation of insulation and during the tank hydrostatic test. Strapping tables should be developed before the tank is put in service in accordance with *API 2550* "Measurement and Calibration of Upright Cylindrical Tanks". The "API Manual of Petroleum Measurement Standards", Chapters 2.2.2 and 2.6 also describes the procedures to be followed for calibrating upright cylindrical tanks.

Tank Accessories - Valves, Instrumentation, Mixers and Appurtenances

These may include:

- A tank level transmitter that, when connected to the associated monitoring system, provides a continuously updated remote indication of the tank fluid level;
- •A tank high level alarm system, which provides a remote high and high-high level alarm that are independent from the main tank gauging system;
- A temperature monitoring system, which transmits the average temperature of the tank contents to the remote tank monitoring system; and
- Tank valves to provide tank isolation from the transfer pipelines.
- The tank level gages and temperature monitoring probes can be connected to a tank monitoring system. Tank monitoring system provides a continuously updated indication of tank levels and the volume of oil corrected to 60°F and provides user selectable tank low and high level alarms.

All instruments and equipment with electrical arcing devices including motors shall meet the applicable electrical hazardous area classification.

Tank Mixers

Installation of variable or fixed angle type mixers will help prevent sludge accumulation on the tank bottom and also prevent product stratification. For product tanks, tank mixers are not necessary unless the tank serves as a blending container. Note that more than one mixer may be necessary to ensure that uniform mixing is achieved.

For tanks with floating roofs, operational caution shall be exercised to ensure that the presence of the floating roof at its lowest position will not interfere with the operation of the mixers.

Valves, Instrumentation and Appurtenances Valve Types

Valve Types

Valve types that are used in conjunction with storage tanks are discussed within the pipeline section of this guide, specifically, gate, plug and ball valves.

Valves that are installed on inlet and outlet lines for tank isolation are often supplied with an actuator for ease and efficiency of operation. Less frequently operated valves tend to be manually operated gate valves. Forged steel gate valves are preferred to isolate tank mounted instruments for maintenance purposes.

Typically, line valves installed at tanks are flanged, while instrument isolation valves are either flanged or welded. Where threaded valves are installed at storage tanks, piping should be designed to facilitate tightening of threaded connections in the event that leakage occurs.

Maintenance, Inspection and Testing

The pipeline section of the guide covers general requirements for maintenance, inspection, and testing of valves. It is important that tank isolation valves be regularly inspected and maintained because of the potential for spillage and expensive disruption to operations if valves do not function correctly. Requirements for the fire test for valves are covered in API Specification 6FA.

External Piping Design

The stresses imposed by the movement of transfer piping caused by tank settlement can be a cause of tank nozzle/piping failure. Sufficient flexibility must be designed into the transfer piping to accommodate this differential movement. Additional stresses exerted on the tank nozzle include thermal stress and water hammer. These stresses need to be considered in the piping design. See example in Figure 9.1.

Stress Analysis

A stress analysis evaluates tank settlement, piping flexibility and support scheme to predict tank nozzle loading. With this analysis, the reinforcing pad for a new tank nozzle can be designed. For alteration of an existing tank, the analysis will indicate whether the reinforcing pad has adequate strength. Refer to *API 650* and *API 653* for further information.

Internal Piping Design

Internal piping, such as heater connecting piping, fill/suction diffuser piping, water draw, etc., are all supported from the tank bottom. In the event of uneven tank settlement, differential movement can create extra loading on the tank nozzle. Consequently the piping and supports have to be carefully designed to minimize the loading transferred onto the shell nozzle and the piping.

Tank Heaters

Tanks can be heated by a variety of methods including:

- Internal or external steam coils.
- Internal heat transfer coils.
- Direct-fired internal "U-tube" heaters

- Internal or external electrical heaters.
- External heat exchangers.

In all cases a heated tank requires external insulation for economical operation. The insulation will usually have an aluminum covering or protective mastic coating for mechanical protection and to provide a barrier against precipitation.

The heaters may be equipped with temperature controllers and protective instrumentation to prevent overheating the liquid or to prevent damage to the heater element by stopping operation at low liquid levels.

External Piping Design Example

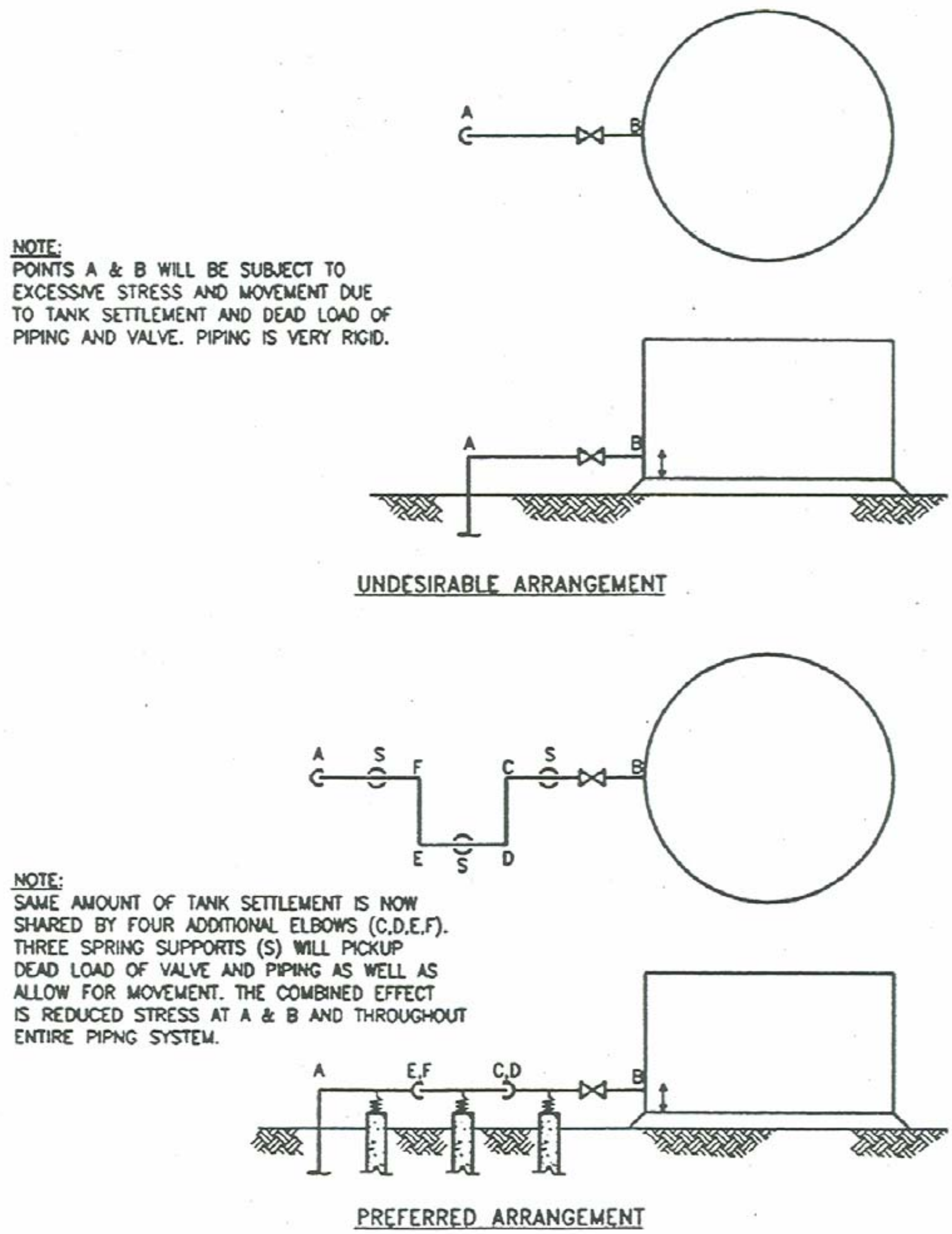


Figure 9.1

Tank Construction Records

Tank construction records may include the following:

- Storage tank data (per *API 650, Appendix L,* or similar data sheet if not *API 650* tank).
- Tank design calculations.
- Rubbing of tank nameplate.
- Complete set of tank design and fabrication drawings.
- Material test report of all plates, piping, fittings, and structural components.
- All non-destructive examination reports including radiographs and hydrostatic test records.
- Settlement records from before, during, and after hydrostatic tests (per API 653, Appendix B).
- All welding procedures, welder qualification test records and weld maps. Tank accessory data
- Certification of code compliance by the tank manufacturer

Fire Protection

Storage tanks shall be provided with fire protection systems as per NFPA 30. Fire protection strategies must be consistent with state and local fire marshal requirements.

Fire Water

The Owner should provide sufficient fire water to protect and cool the site tankage by means of a network of hydrants and monitors. Sufficient numbers of hydrants and monitors should provide coverage on all sides of a tank, including the entire roof. (See Figure 9.2). The capacity of the fire water supply system should be large enough to sufficiently cool a potential tank on fire (i.e., prevent shell splitting and prevent the heat intensity from affecting adjacent tanks). Hydrant mounted monitors are recommended to manage water flows for maximum manpower utilization during emergencies.

Foam System

An oil storage tank may be equipped with a foam system. (See Figure 9.2 and 9.3). This consists of a foam proportioning unit, fire water supply, foam delivery piping network to deliver foam solution to the tank top and a foam generator/chamber which will aerate the solution to form foam. The foam is then distributed over the tank top, smothering the fire.

For tanks with floating roofs, the foam will fill the gap between the tank shell and the perimeter of the floater. For fixed roof tanks, the foam will cover the entire liquid surface.

The foam proportioning unit is used to mix the foam concentrate and fire water in pre-determined proportions. Ina fixed system, all units are permanently piped to the tank Ina semi-faced system, the foam proportioning unit is mounted on a trailer. This portable trailer can be located as needed in any emergency. It is fed with water from a nearby fire hydrant with a fire hose. The portable foam unit will be connected to the hard piping system that runs to the top of the tank

Codes

Fire water and foam systems shall be designed, built and tested in accordance with one of the following codes:

NFPA-11	Low expansion foam and combined agent systems.
NFPA-IIA	Medium and high expansion foam systems
*NFPA-II*C	Foam apparatus; Mobile.
NFPA-24	Private service mains and their appurtenances.

Lightning and Electrical Fire Hazard Protection

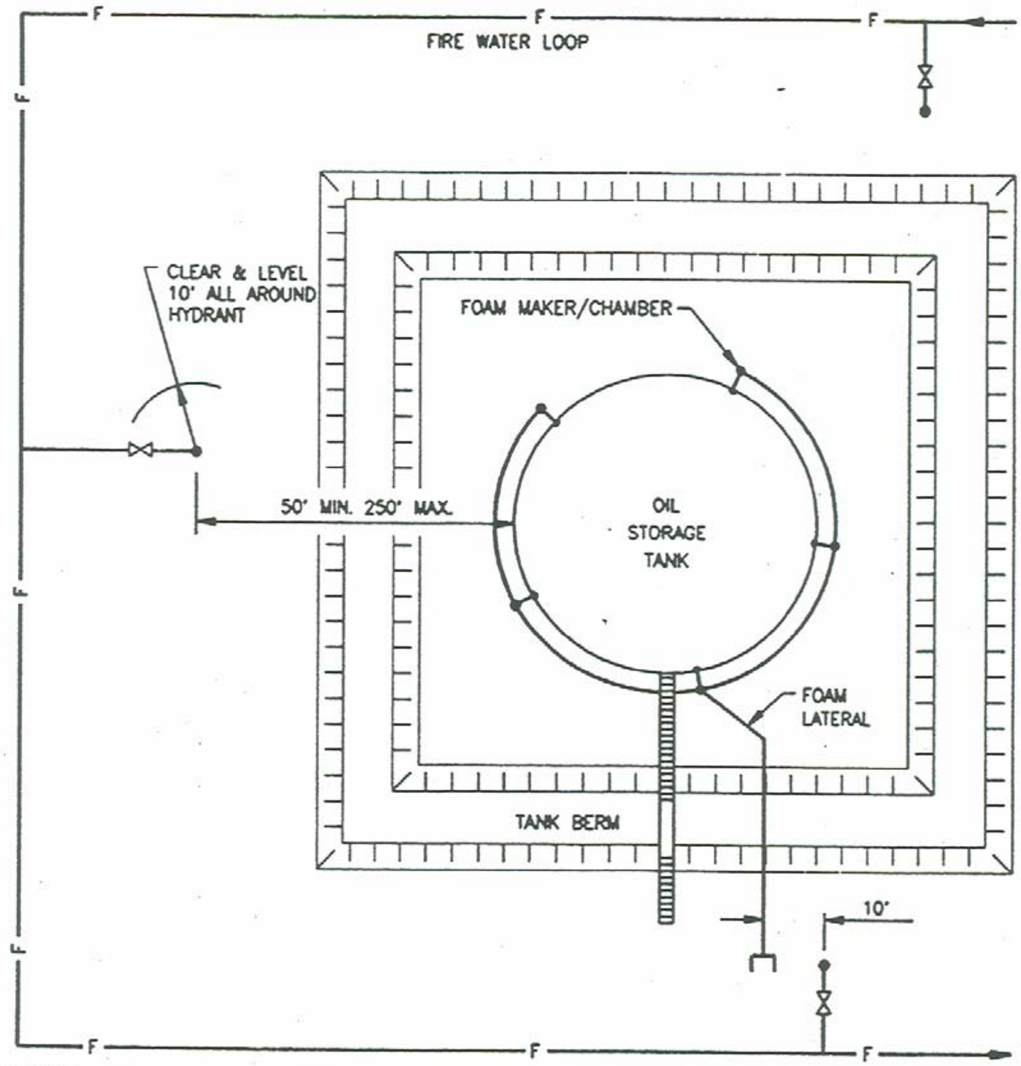
Oil storage tanks should be protected against lightning and also against discharge of static electricity which can cause ignition of tank contents or hydrocarbon vapors. This can be achieved by ensuring electrical continuity of the shell, float, roof and accessories with the grounding grids around the tank. Other design conditions or considerations are:

- Install sufficient ground rods around the tank perimeter and bond the ground rods directly to the tank shell at the base plate with bonding cables and clips.
- Mount disbursal arrays connecting the tank shell to the roof rim and bond to a separate ground rod grid system. This is the usual choice for open top, external floating roof tanks. In addition, external floating roof gauge platforms are bonded to the rolling ladder and the rolling ladder to the roof, using bonding cables.
- Use conic disbursal arrays on supported and self-supporting external roof installations.
- All electrical equipment and instruments with electrical arcing devices shall meet the requirements of the applicable electrical hazardous area classification.

The following codes may be referenced for grounding design, installation and testing.

ANSI/NFPA 70	*National Electrical Code*
ANSUNFPA 77	*Static Electricity*
ANSI/NFPA 780	*Lightning Protection Corte*

Typical Fire Protection of Oil Storage Tank

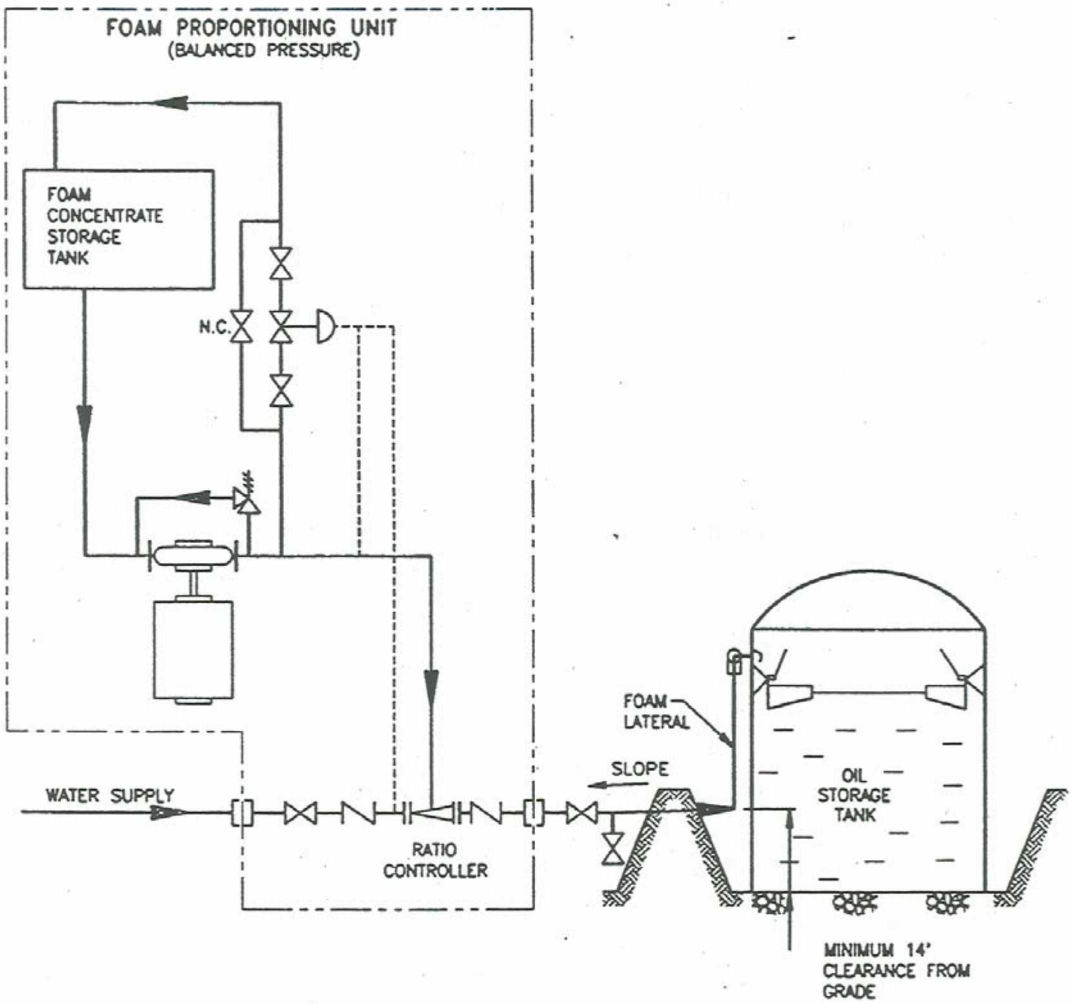


NOTES:

1. MINIMUM 3 HYDRANTS TO BE WITHIN 50' TO 250' OF TANK PERIMETER.
2. FOAM CONNECTION OF SEMI-FIXED SYSTEM TO BE LOCATED OUTSIDE TANK DIKE, UPWIND AND WITHIN 10' OF HYDRANT.
3. SPACING OF FOAM MAKER/CHAMBERS FOR 2" HEIGHT FOAM DAM SHALL NOT EXCEED A MAXIMUM SPACING OF 80'.

Figure 9.2

Typical Foam System Schematic



NOTES:

1. FOR A SEMI-FIXED SYSTEM, THE FOAM UNIT WILL EITHER BE MOUNTED ON A TRAILER OR A TRUCK. THE PUMP WILL BE DIESEL ENGINE-DRIVEN. THE SOURCE OF WATER WILL BE FROM THE HYDRANT.
2. FOR A FIXED SYSTEM, PERMANENT PIPING WILL BE INSTALLED AND WEATHER PROTECTED (FROM FOAM UNIT TO FOAM LATERAL).

Figure 9.3

Overfill Protection

(2) The owner or operator shall ensure that the means of preventing storage tank overfill comply with the 1993 version of the National Fire Protection Association (NFPA), Flammable and Combustible Code, No. 30, Chapter 2, Section 2-10.

Tank overfills may be caused by human error, tank level equipment malfunction or a lack of procedures or training. Facility complexity, different tank elevations, data transmission systems, automatic tank gauging systems, frequency of filling and operator error are all factors which may be involved in storage tank overfills.

Code

Overfill protection shall be in accordance with *.NFPA 30, Chapter 2, Section 2-10. API recommended practice 2350,* Overfill Protection for Petroleum Storage Tanks was prepared in accordance with *NFPA 30* and may be used for additional information regarding overfill protection.

Provisions for Overfill Prevention

Redundant High Level and High-High Level Switches and Remotely Controlled Tank Valves

Stand alone independent switches are recommended. The high level switch will signify when a high level is reached to provide the operator sufficient time to initiate valve, pump or transfer shutdown. The high-high level switch could be used to automatically shut down the tank valve, pump, transfer or divert the flow to another tank. The high high level switch must be controlled by a device independent of the high level indicator.

The alarm levels shall be determined by the maximum tank fill rate and the response time involved with shut down operation. Sufficient time shall be allowed for closing the valve and shutting down the pumps to avoid pressure surges. See Figure 9.4 for typical tank level switch setting.

Frequent Gauging by Operator

Facilities not equipped with overfill alarms must be frequently gauged by a person continually on the premises with frequent acknowledged communication maintained with the supplier so flow may be properly controlled.

Properly monitoring storage tanks without overfill alarms requires that the:

1. Normal fill level be established and prominently displayed near the tank gauge hatch or at ground level;

2. Tank capacity be gauged prior to transfer to ensure appropriate capacity;

3. Frequent communication be maintained with the supplier so oil flow can be controlled;

4. Tank receiving oil should be checked immediately after startup and frequently during the transfer to confirm anticipated oil flow and to check operation of gauging system;

5. Gauge readings should be recorded;

6. Tank area should be inspected to ensure the integrity of piping valves and pumps; and

7. Personnel should be present at the tank as the tank reaches its fill level. During this time the tank should be monitored continuously until the transfer is completed.

Automatic tank gauging system

It should provide:

1. 1A continuous level measurement with suitable accuracy,
2. An adjustable high and low level alarm for each tank; and
3. Correct tank strapping table data for each tank. (Since above ground storage tanks are not true cylinders, strapping tables are utilized to give the actual tank volume at a number of tank levels. The tank strapping table corrects for volume displaced by the floating roof and tank internal fill/suction piping, tank bottom flexing, tank bulging, etc.).
4. A continuous tank monitoring system such as a PC-based system taking as input the current tank level, temperature, strapping table and pre-set levels (high and high high). 9-23

The float and tape type level transmitter is preferred. For a floating roof tank the tape is usually attached to a guided float in a stilling well. See Figure 9.5. For fixed roof tanks, it is usually attached to a guided float inside a stilling well.

Local indication is provided for field verification of tank level.

Automatic tank gauges may also be used for leak detection. This requires a gauge accuracy of ± 1/8 inch or better and tank temperature volume correction to 60° F. Monitoring accuracy will decrease with increasing tank diameters.

Written Operating Procedures and Training

To prevent overfilling the storage tank, written operating procedures for receipt of oil and training of operators shall be established by the owner as identified in *WAC 173-180B Facility Oil Handling Operations Manual Standard*. The procedures should be specific to location and local conditions.

The operating procedure shall address:

- Planning of oil delivery or receipt, determining the quantity, available tank capacity, piping/valving arrangement for the receipt, tank levels (current and high levels), contact person of transporter.
- Continuous monitoring of the receipt, having current knowledge of tank levels and quantity yet to be received, fill rate, anticipated final tank level, correct piping and valve line-up, continual contact with the transporter.
- Completing the receipt including routine shutdown procedures, ensuring correct tank valve is closed. Notification to transporter for pump shut down.

- Emergency shutdown, an orderly procedure to perform an unplanned shutdown of tank valves and transfer pumps. It may involve the choice of diverting flow to another tank. If diversion is the only choice, piping and valve system line-up shall be pre-planned.

- Personnel performance evaluation and training.

Storage Tank Inspection, Testing and Verification

A routine maintenance and testing program should be in place to ensure that all hardware and monitoring systems will function as designed. It shall address the interval of the inspection and testing procedures for each component and system. The manufacturer's recommendation should be taken into account when determining schedules, frequencies and procedures for equipment testing and maintenance.

Maintenance inspections should include diagnostic routines to permit identification and repair of failures. False alarms will decrease confidence in overfill protection measures and should therefore be corrected as soon as possible.

The measuring instruments (the tank gauging system and temperature sensors should be checked and calibrated to ensure they represent accurate field data. The tank gauges should be checked against manual level measurements also known as "hand gauging " the tank.

The level switches should be functionally checked to ensure they will signal high tank level.

All automatic tank valves should be checked for functionality and the valve status (open or closed) verified.

The entire tank level monitoring and alarm system should be tested functionally with simulated high and high-high levels.

Typical Tank Level Setting

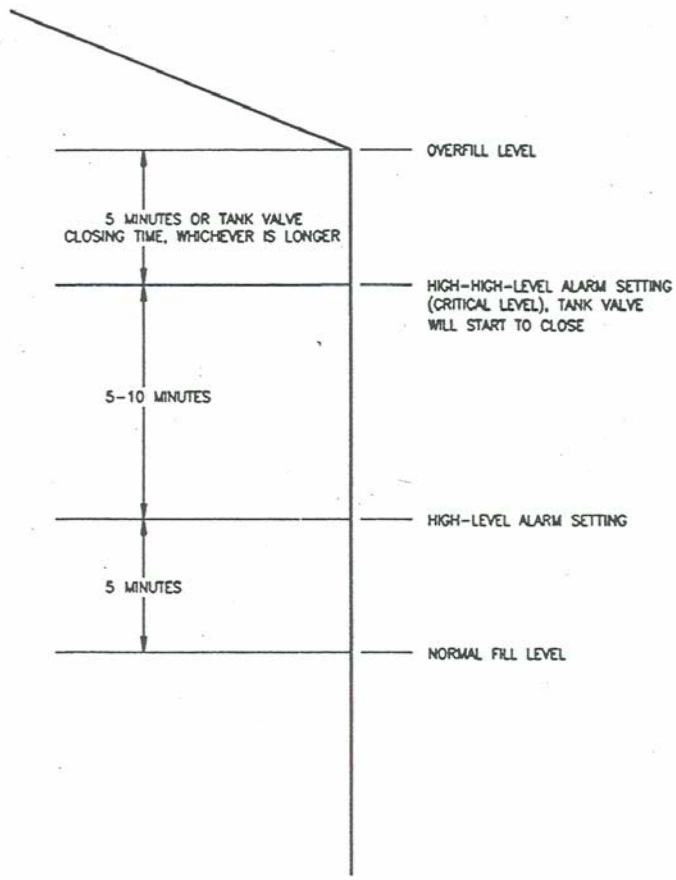
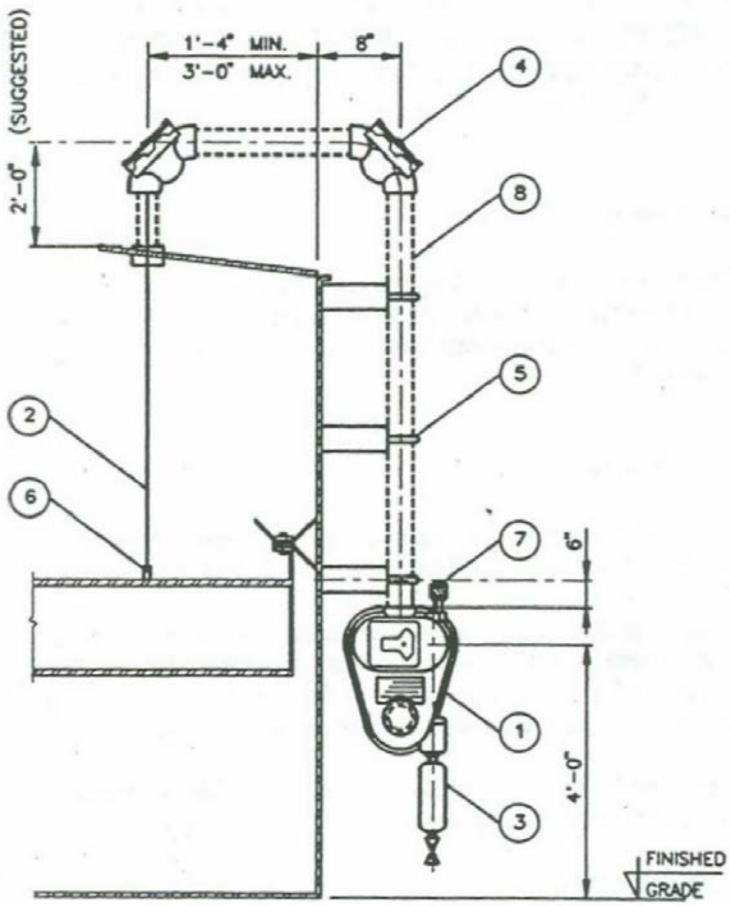


Figure 9.4

Typical Level Transmitter Installation Cone Roof Tank With Internal Floating Pan



LEGEND

1	GAUGE HEAD	5	PIPE SUPPORT BRACKET
2	TAPE	6	TAPE FASTENER
3	CONDENSATE POT C/W VALVE	7	BREATHER VENT
4	SHEAVE ELBOW	8	NPS 1 1/2 " PIPE AND FITTINGS

Figure 9.5

Inspection and Integrity Assessment

(3) Storage tanks shall be maintained, repaired and inspected in accordance with the requirements of API 653 dated January 1991 unless the operator proposes an equivalent inspection strategy which is approved by the department.

To ensure the integrity of an oil storage tank and to minimize leakage throughout its service life, periodic inspection of the tank, accessories and foundations is required. All observations and measurements taken during these inspections shall be evaluated, appropriate repair plans prepared, and future inspections scheduled.

External Inspection/In-Service

External inspections may be classified as routine in-service inspections, scheduled inspections, or in-service ultrasonic thickness measurement of shell. Inspection frequencies are listed in Table 9.1.

The owner shall initiate a program of regular periodic inspections (minimum monthly) for any sign of leakage, shell distortion, settlement,' drainage, etc. and any observation that is abnormal Any findings should be recorded and reported to management for further investigation and action. The owner should prepare the inspection check list to ensure all key areas are visually inspected and recorded.

Any formal detailed external inspections shall be carried out by qualified inspectors on a scheduled basis. The Inspector may use the checklists in *Table CI of API 653, Appendix C.*

Other items to be inspected include:

a) Measurements of shell thickness and observations/calculations of corrosion rates (refer to *API 653, Section 2*).

b) Tests of the cathodic protection system.

c) Inspection of the grounding system.

Internal Inspection/Out of Service

Internal inspections can only be performed when tanks are out of service and the tank interior is gas free and safe for any repair work *API 2015 Safe Entry and Cleaning of Petroleum Storage Tanks, Planning, and Managing Tank Entry from Decommissioning through Recommissioning* provide guidelines for tank entry which will help operators comply with OSHA confined space regulations. During any internal inspections, the tank bottom and interior of the shell shall be visually examined for indications of corrosion and settlement by qualified inspectors who may complete the checklist in Table C2 of *API 653, Appendix C.* Refer to appendix G for additional information on *API 653* inspection strategies.

TABLE 9.1

TANK INSPECTION PERIOD 'PER API 653

INSPECTION	PERIOD	REFERENCE	BY	INSPECTION POINTS
External, routine in service visual	≥Month	*API 653 Section 4.3.1*	Owner/ Operator	<u>INSPECTION POINTS</u> Checklist:
External. formal visual, in-service or out-of -service	≥5 years or 25%, 50% or 75% of corrosion rate of the shell whichever is less	*API 6S3 Section 4.3.2*	Qualified Inspector	Leak. Shell distortion, Settlement, Corrosion, Foundation, Paint , Coating, Insulation,
In-service UT	5 years after new tank commissioning -Every 5 years if corrosion rate not known -If corrosion rate is known. 15 years or period=RCA/2N years whichever is less -RCA=remaining corrosion allowance{mils) --N=she~ corrosion rate(mils/year)	*API 653 Section 4.3.3*	Qualified inspector	Appurtenenances Per checklist *C-I of API 653* -Cathodic protection survey per *API 651* -Condition of exterior shell and roof -Tank grounding system per *API 651, RP 2003* Sufficient UT Measurement establish a rate of uniform general corrosion
Internal out-of-service	-If bottom corrosion rate is known:20 years or (whichever less), interval (calculated based on measured or anticipated corrosion rate) that at next inspection, bottom thickness is not less than per table 4-1 of API 653 -If corrosion rate is not known: 10 years	*API 653 Section 4.4*	Qualified inspector	Per checklist, *Table C2 of API 653*

Tank Integrity Evaluation

With data and observations obtained from the foregoing inspections, the integrity of oil storage tanks to provide leak free service life in the future can be evaluated. The evaluation shall be performed in accordance with *API 653, Section 2*.

Section 2 addresses:

1. Shell thickness - measured vs required minimum.
2. Shell distortion - identify reasons for distortion (settlement, pressure, workmanship, etc.) and the combined effect with corrosion.
3. Welds and flaws - cracks, laminations, arc strikes, deterioration or cracks in shell course butt welds, bottom fillet welds, etc., from corrosion or settlement.
4. Appurtenances - deterioration, distortion or cracks on nozzles and reinforcement plates due to corrosion and settlement.
5. Bottom thickness - measured vs. required minimum.
6. Protection from tank bottom corrosion:
    - Effectiveness of cathodic protection system (*per API 651*).
    - Condition of tank bottom lining (*per API 652*).
7. Tank foundation:
    - settlement
    - erosion
    - deterioration
    - ponding
    - cracking

If the results of any integrity evaluation prove continued suitability for service, future inspection dates can be established based on observed corrosion rates. If such evaluations conclude the need for immediate repair work, then it is necessary to establish a tank repair plan. Schedules for future inspection(s) shall also be established.

Compliance Strategies

The owner/operator shall comply with the requirements for inspection as per *API 653* referred codes and the following guidelines.

1. Inspection Schedule and Checklist
2. Integrity Evaluation

The report including recommendations for integrity evaluation shall be prepared by qualified inspector(s) in accordance with API 653, Section 2 and inspection results. It shall recommend the next inspection period, and any corrective/repair work required.

Review Procedure

The owner/operator shall maintain on file complete inspection reports, repair plans and records, and integrity evaluation reports for each tank during its entire service life. These reports shall be available for review by the Department of Ecology at any time.

Tank Repair/Alteration

As a result of any tank integrity evaluation, a tank repair plan should be developed and implemented as required to maintain the tank integrity until future inspections.

Tank repair and non-destructive examinations shall be performed in accordance with Section 7 and Section 10 of API 653 respectively.

All necessary records and certification of the repair shall be completed and maintained by the owner/operator throughout the entire service life of the tank in accordance with Section 11 of API 653. The new nameplate shall be attached to the tank adjacent to the existing nameplate for alterations. A tank repair is work necessary to restore a tank to condition suitable for operation. An alteration is work that changes the physical dimension/configuration of the tank

Tank Repair/Alteration Plan should include all necessary information, drawings and forms for tank repair and testing. The owner/operator should be cognizant of the following issues as applicable:

Section 1: Before Tank Shut Preparation down--List all prefabrication, materials, equipment, safety precautions and procedures; preparation work prior to tank shutdown, and emergency plans.

Section 2: Repair Work Scope and Procedures--Identify items to repair/replace, procedures to use, material and equipment requirements. Include an execution plan and schedule with milestone dates and logical sequence of events ('including tank isolation and return to service).

Section 3: Testing and NDE Requirements--Address all necessary testing (hydro, UT, radiography radiography, vacuum, impact, etc.) before, during and after the repairs.

Section 4: Attachments--Include necessary NDE forms, drawings, certification of repair to API 653, etc.

Tank Settlement

Tank settlement should be measured during the hydrostatic testing and will form the base for future measurements and analysis. These measurements should be in accordance with *API 653, Appendix B* for new and existing tanks.

Tank settlement is primarily caused by poor soil conditions and/or a high water table and/or inadequate foundation support. Excessive tank settlement could result in tank failure by tank bottom fracture and/or tank nozzle piping breakage due to excessive stress. See Figure 9.6.

The inspector shall look for shell/baseplate deformations and fractured welds as depicted by Figure 9.6. Review of the settlement history/record of the tank shell and tank bottom shall be done to ensure that the settlement rate has been reduced and the overall settlement since erection is within design limits.

Effect of Tank Settlement

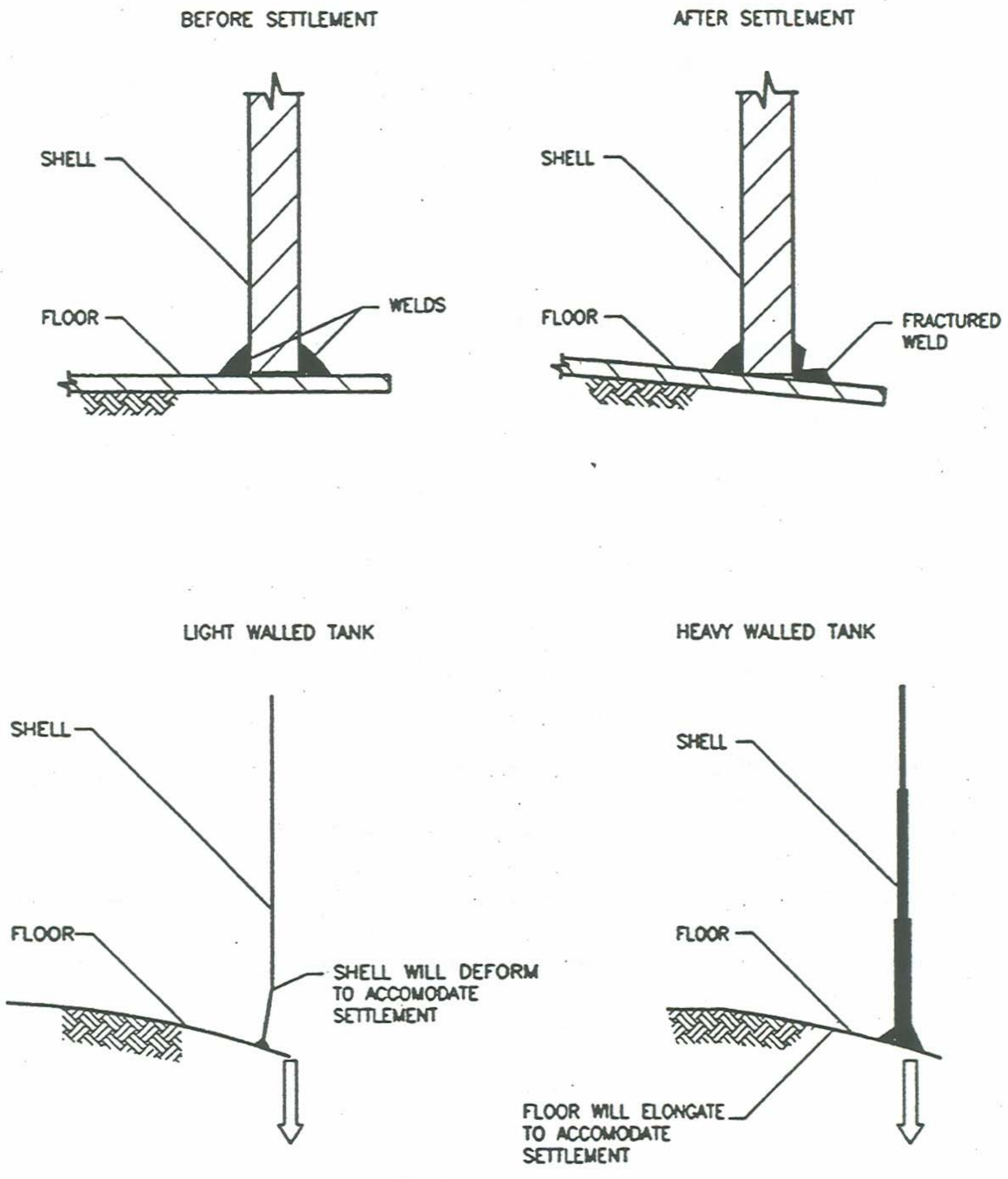


Figure 9.6

Corrosion Control

Codes

The following codes are recommended for corrosion control of oil storage tanks.

API 651	*Cathodic protection of above ground petroleum storage tanks*
API 652	*Lining of above ground petroleum storage tank bottoms.*
NACE RP0169	*Control of external corrosion on underground or submerged metallic piping systems.*
NACE RP0285	*Control of external corrosion on metallic buried partially buried or submerged liquid storage systems.*
NACE 6A187	*Reinforced polyester and epoxy lining.*

Causes of Corrosion

Appendix H provides a brief introduction on corrosion and corrosion control basics.

Corrosion Prevention

Tank Bottom (Interior) Corrosion

Internal tank bottom corrosion is caused oxygen entrained in sludge and water. Crude storage tanks usually experience more corrosion problems than product tanks because of the higher concentrations of water and sludge.

To reduce tank bottom corrosion, one or more of the following methods may be employed: Lining of Tank Bottom

Lining the tank bottom with a non-conductive coating will prevent the flow of current and the establishment of electro-chemical corrosion cells. For new tanks, thin film lining is appropriate. For old tank bottoms, thick film lining could be appropriate. Refer to API 652. The lining thickness and its electrical continuity shall be confirmed prior to acceptance. Tank bottom lining is more effective than other methods provided the floor has been prepared properly (sandblasting, cleaning, priming, no sharp corners, etc.), the lining has been properly applied (good adhesion, sufficient curing and top sealing coat) and the entire tank bottom is fully supported (good foundation, minimum settlement, minimum flexing of bottom plates). Surface preparation is critical to proper coating application. Sandblasting and coating application must be in accordance with the constraints established by the coating manufacturer. Refer to Table 9.2 for recommended inspections during tank bottom coating.

Cathodic Protection

For a double bottom tank sitting on top of a non-metallic, impervious membrane (as a secondary containment technique), the new (upper) bottom should be protected against corrosion by embedding anodes in the sand between the old (lower) and new (upper) bottom or by another suitable practice.

TABLE 9.2

INSPECTIONS DURING APPLICATION OF INTERIOR COATING

STEP	ACTION
Prior to preparation of tanks(s) for cleaning and repair	Safety inspection
After cleaning of tank(s) prior to abrasive blasting	Safety inspection removal of dirt, and debris. and any hindrance to abrasive blasting
After abrasive blasting	Surface inspection for appropriate finish for coating application (critical) Inspect for visible rusting. and if present, reblast before applying primer (if required)
During and after coating	Observe proper timing and thickness of layers (color coating coatings will allow you to keep track of multiple coatings) Check for pinholes, blisters. inadequate coating thickness. and other defects Inspect for fiJm imperfections using a holiday detector Conduct a fill test
After final cleanup	Ensure that facilities around the site are restored to their initial condition

Source: NA VFAC NFGS-09872

Tank Bottom (underside) Corrosion

Underside tank floor corrosion is caused by a combination of

- accumulation of oxygen within moisture around and underside of the tank bottom, either from runoff or high ground water level;

- debris or dissimilar soils or materials included in the compacted backfill material under the tank;
- stray electrical currents from outside sources which may include cathodic protection devices from other systems;
- dissimilar metals;
- soil with low pH (less than 6.5) and/or low resistivity.

To reduce underside tank bottom corrosion, cathodic protection may be considered:

Installation of cathodic protection on the tank bottom will cause the tank bottom to be cathodic, thus reversing the current flow of the electro-chemical corrosion cell thereby preventing loss of metal. The cathodic protection method should be as per API 651.

It is especially important to cathodically protect the bottoms of existing tanks located on sites subjected to high moisture content or on foundations of unsuitable materials.

The design of a cathodic protection system shall take into account local site conditions, adjacent sources of stray current, soil resistivity, nearby buried structures and tank foundation design.

Tank Top Corrosion

Corrosion of the shell exterior, top of the fixed root or top of the float on open floating roof tanks are caused by moisture in the atmosphere as well as stagnant precipitation. Again, corrosion of this type will not normally cause tank leakage, is easily detected, and can be corrected by painting and improved drainage. Ambient temperature tanks are coated primarily for aesthetics and heat absorption/reflection.

For heated tanks, corrosion under insulation is a condition which must be monitored to ensure the integrity of the tank shell exterior.

Corrosion Surveys

Tanks shall be inspected and surveyed for corrosion on a regular basis to provide an assessment of their structural integrity. Necessary repairs shall be scheduled in order to extend service life. Inspection intervals shall be established per API 653 and records shall be kept for the life of the tank.

Tank Bottom Corrosion Surveys

Tank floors shall be inspected while tanks are out of service. Visual inspection of the entire floor and internal appurtenances shall be conducted to identify metal pitting and general corrosion. The checklist in appendix C of API 653 describes the steps in an internal tank bottom inspection. The location of corrosion sites along with depths and extensions shall be measured and compared with previous records. Plate thickness shall be measured with ultra sonic, electromagnetic flux or other acceptable methods throughout the entire bottom and the data shall be compared with previous records. Coupons may be cut out to confirm any indicated underside corrosion.

Tank foundations shall be inspected for evidence of stagnant water, deterioration, signs of internal leakage and rust spots. Inspection shall be per API 653.

Cathodic Protection Surveys

The cathodic protection system should be inspected regularly to ensure that the components are functioning as designed. The survey should be per API 651.

Tank Lining Survey

Inspection of the tank lining shall be performed when tanks are out of service. Discoloration of the lining, signs of erosion, (especially around the fill/suction nozzle), non-adhesion, pin holes and discontinued surfaces (by holiday test), lining deterioration, breakage due to tank bottom movement or settlement, etc. shall be recorded by category, location and physical size. Follow procedure and method of lining inspection as *per API 652, Section 7.* A repair plan shall be established and scheduled dependent upon the severity of damage.

Storage Tank Records

(4) A record of all inspection results and corrective actions taken must be kept for the service life of the tank and must be available to the department for inspection and copying upon request.

The tank owner/operator shall maintain all records covering tank design, construction, materials, non-destructive examinations, inspections, repair and integrity assessments throughout the entire service life of the tank These records shall be securely maintained and be readily available for review by the department of Ecology inspector. Organization of records should be up to the discretion of the facility.

The list of records may include, but not necessarily be limited to, the following

Periodic Tank Inspection Record

- Routine in-service inspection (external) records.
- Formal in-service inspection (external) checklists (Table CI of *API 653, Appendix C* or its equivalent).
- Formal out-of-service inspection checklists (Table C2 of *API 653, Appendix C* or its equivalent).
- Tank shell and bottom thickness measurement records.
- Tank integrity assessment reports.
- Tank shell and bottom corrosion rates and their calculation.
- Tank settlement records.
- Cathodic protection test records.
- Tank lining inspection/test records.

Tank Repair Records may include:

- Design drawings and calculations of the repairs (including location of repair, type and extent of repair).

- Material test reports.
- All NDE records including radiograph and hydrostatic testing.
- Certification of repair (per *API* 653, *Section 11*).

Leak Detection

To detect leakage from storage tanks, the following methods could be employed:

Secondary Containment

Any leakage from storage tanks shall be collected within secondary containment basin(s). Hydrocarbon detectors may be installed within the secondary containment area to detect and alarm the presence of hydrocarbons. Drainage into the area and the entire tank farm, including surface runoff shall not be discharged into the environment until it is free of hydrocarbons. (For further information, refer to the "Secondary Containment" portion of this manual).

Leak impact can be minimized by installing an impervious soil or synthetic geomembrane liner beneath the tank bottom to serve as secondary containment for potential leaks and to isolate the tank bottom from moisture and ground water. *Appendix I of API 650* describes this practice in greater detail. Since this practice traps moisture a method of draining the liner must be installed. This type of system may also impact the performance of cathodic protection systems so any design should consider the interaction of these systems.

Double Bottoms

For tanks with double bottoms, any leakage liquid shall be directed from the space between the two bottoms to a location outside the tank. A hydrocarbon detector could be installed to detect leakage. Refer to *appendix I in API 650* for further information regarding double bottoms.

Inventory Control

Leakage from a tank can be detected by comparing the liquid volumes added or removed from the tank via connected pipelines with the corresponding tank volume change. The volumes are corrected to 60°F. This method of leak detection is not considered reliable, especially for small leaks.

Tank levels can be easily measured to the nearest 1/4 inch. For a typical 40 foot high tank, an error of inch represents a liquid volume error of only 0.05% of total tank capacity. The probable error in tank volume changes determined from level measurements depends on the magnitude of the change in level. For example, a 10% level change would have a probable volume change error of 0.5% whereas for a 50% level change the probable volume change error is only 0.1%.

Flowmeters (or the level changes in connected tanks) are used to determine the volumes added or removed from the monitored tank. The tank level change (usually measured with an automatic gauge) is used with the tank strapping tables to calculate the change in tank volume in the monitored tank. Any discrepancy between the tank volume change and the liquid volumes added or removed may indicate a leak A PC-based tank monitoring system could be used to carry out the calculations and alarm when a leak is detected.

The overall accuracy depends on the method used to determine the volume added or removed from the monitored tank When the change in level in another tank is used, the error in measuring the level change adds to the overall error in leak detection. In cases where a flowmeter is used, the error in flow measurement adds to the overall error in leak detection. Appendix J, "*Evaluation of Mass Balance Leak Detection System with Respect to Oil Transfer Pipelines*" provides information on the accuracy of flowmeters and tank volumes calculated from tank levels.

API publication 306 dated October 1991 entitled "An Engineering Assessment of Volumetric Methods of Leak Detection in Aboveground Storage Tanks" concluded that differential pressure measurement methods of leak detection can be used to detect small leaks. To be successful these systems must account for thermal expansion, evaporation and condensation of product.

Statistical Analysis

This method relies on a statistical analysis of hand tank gauging measurements in a standing tank to determine the probability of a leak

Acoustic Emission

Piezoelectric acoustic detectors are temporarily attached to the outside of the tank with the suspected leak to detect the characteristic noise spectrum generated by the leak Field trials have been successful in locating leaks in tanks.

For additional information refer to *API publication 307 dated January 1992 and titled "An Engineering Assessment of Acoustic Methods of Leak Detection in Aboveground Storage Tanks.*"- This report concludes that though passive acoustic systems can be used to detect small leaks in aboveground storage tanks, the data acquisition and signal processing needs to be improved.

Chapter 10

WAC 173-180A-100 TRANSFER PIPELINE REQUIREMENTS

The following is intended as a guide for oil facility operators and inspectors to clarify oil transfer pipeline compliance requirements and compliance alternatives. This is not intended to be a design handbook. For details of minimum requirements for the design, materials selection, construction assembly, inspection and testing, see the various regulations and standards referenced in Appendix D of this manual. Where references to codes or standards are made, the reader shall consult the latest current revision.

Transfer pipelines include those pipelines which connect a transmission pipeline or tank vessel to the facility. The transfer pipeline requirement is intended to cover the portions of the facility which would directly impact waters of the state in the event of a spill. A transfer pipeline includes valves, manifolds, pumps, and appurtenances for the transfer of oil.

Types of Pipelines

Types of Materials

Proper piping design must take into account the hoop stresses caused by internal pressure including surges; and structural stresses due to external loads including surface live and dead loads (from overburden, rail or truck, differential settlement, bending, earthquake and other shear loads). Where appropriate, consideration should be given to vacuum loads and thermal stress and strain.

The system designer and operator must always be cognizant of the dangers of stress concentration factors which increase the local stress level. Often this can be increased by orders of magnitude beyond the capacity of the pipe material. These include for example notches, arc strikes, local damage, denting or ring grooves.

Welded carbon steel pipe is selected for its strength and mechanical properties at reasonable cost and is generally used in oil transfer facilities for various pressure and flow rates. Within the facility, steel pipe is normally installed above grade for maintenance and inspection but when placed outside the facility in public right-of-way areas, the pipe is usually buried for operating security and protection from third

party damage. Because of possible leaks, bolted flanges and threaded joints are normally avoided below ground. It is recommended that these types of connections be placed in a vault or manhole for accessibility.

Cast iron pipe is more brittle than carbon steel pipe and is unable to withstand the tensile forces generated in pipelines. Hence, it should not be used for hydrocarbon service.

Ductile iron pipe is used occasionally, principally for water and non-hydrocarbon service. As the name implies, ductile iron pipe has a more ductile grain structure than cast iron, but still retains brittle properties.

Types of Steel Pipelines

Weld requirements are addressed in *ASME/ANSI B31.3 and B31.4*. There are three main types of steel pipe, all of which are commonly used in pipelines;

1. Seamless pipe, for smaller diameters and up to 16-24 inch. The maximum diameter varies with manufacturers' capabilities.
2. Longitudinally welded pipe is made by rolling a sheet of steel and welding along a seam. Two welding procedures may be employed: submerged arc welding, with metal added under a bed of protective flux, electric resistance welding (ERW), with fusion achieved by applying a very high local current at the joint to be welded.
3. Spiral welded pipe is made by winding and welding in a spiral or a steel strip fed by rollers. Reliable results can be obtained with high quality control.

Steel pipe is commonly manufactured as seamless pipe but a more economical design has a longitudinal straight or spiral welded joint. The method of welding requires a weld joint quality factor be applied when the design operating pressure is established.

The circumferential weld connecting each pipe section is either executed manually or by a machine welder in the field. A certain percentage of the connection welds are radiographically inspected. This percentage varies depending on the piping design code and whether or not the weld is a tie-in weld.

Pipeline Construction

(1) Pipelines replaced, relocated or constructed after the adoption date of this rule which are located in areas not controlled by the facility shall be installed in accordance with 49 C.F.R. 195.246 through 49 C.F.R. 195.254 as amended on October 8, 1991, where feasible. Facility control is established by fencing, barriers or other method accepted by the department which protects the pipe right-of-way and limits access to personnel authorized by the facility.

The installation of pipe below ground shall be executed using the procedures outlined in 49 *CFR 195. Also, A..S /ANSI B3I.4 - 434.10 and 434.11* provide installation guidelines. It is important to avoid stresses during pipe placement to eliminate local damage or failure. Special precautions should also be taken in handling and construction if the ratio of pipe diameter to wall thickness is high.

The placement of a rock free backfill base will reduce the risk of mechanical damage to the pipeline. The damage caused by these conditions could cause failure when the pipeline is pressurized.

The required cover for new buried pipelines should *49 CFR 195.248* which recommends minimum cover for different classifications. Proper engineering evaluation of the required cover for safe operation is mandatory in all Codes and Standards.

Buried pipelines should maintain a minimum clearance of 12 inches from underground structures in accordance with *49 CFR 195.250*.

The installation work should be monitored and inspected by the owner's qualified independent inspector as required in *ASME/ANSI B31.4 Chapter VI "Inspection and Testing'*: This is intended to assure that all work is performed in accordance with the drawings, specifications, and regulations to provide for the future safe operation of the pipeline.

Third Party Damage

(2) All pipelines shall be protected from third party damage in a reasonable manner and be able to withstand external forces exerted upon them. This shall be done by:

(a) Registering all underground pipelines located in public right-of-way areas in the local one call system if available;

To reduce the possibility of damages to buried facilities by excavators, the Utilities Underground Location Center in Bellevue, Washington supplies a one number locator free pipeline service "**Call Before You Dig**", (1-800-424-5555) to all excavators. This service area covers most of Washington and is financially supported by the subscribers with underground facilities.

(b) Maintaining accurate maps for all underground piping located outside the facility. The maps shall identify pipe size and location. The approximate depths of pipelines shall be identified for pipelines which do not comply with 49 C.F.R. 195.248 as amended on October 8, 1991;

Accurate maps shall be maintained for all underground piping located outside the facility, showing pipe size, location, and depth. The list of facilities in *49 CFR 195.404* "Maps and Records" may be used as a guide. Copies of these maps shall be readily available for local spill authorities and fire departments for use in an emergency.

To enable existing transfer pipelines to comply with this requirement, several pipeline survey systems are available to determine location and depth of the pipeline from above ground.

(c) Marking all piping located in areas not controlled by the facility in accordance with *49 C.F.R. 195.410 as amended on October 8, 1991*;

All buried pipelines outside the facility shall have warning signs as required in *49 CFR 195.410.* The sign shall state "Warning, Buried Pipe" with the type of hazardous liquid, company name, and 24-hour telephone number in at least one inch letters on a contrasting background. Signs should be located at property lines, road and rail crossings, and at intervals as judged necessary. *ASMF./ANSI B31.4* and *API RP 1109* may be used for guidance. Line markers are not required in heavily developed urban areas though lines may be marked on streets and sidewalks subject to conditions by local authorities.

(d) Providing easement inspections of areas identified by subsection (2)(b) of this section on a weekly basis to determine if there is any uncommon activity occurring which may affect the integrity of the pipeline;

A regular visual inspection of piping located outside the facility must be made to observe any changes or damage to the pipe above ground. Surveillance is normally carried out on a regular basis along the routing of major pipelines to look for potential exposure, damage or leakage.

(e) Ensuring that pipelines at each railroad, highway or road crossing are designed and installed to adequately withstand the dynamic forces exerted by anticipated traffic loads*.*

Buried pipeline at railroad, highway, or road crossings may be designed and installed in accordance with *API RP 1102* and as required by *ASMFJANSI B31.4, Section 434.13.4* to adequately withstand all the loads which could impact the pipeline. Prior to installation, an agreement should be made with each crossing and property owner defining the details with a drawing. These codes provide alternate methods of design including increased depth of cover, heavier wall pipe or protection sleeves. The alternate selected design complete with all design details, should be based on sound engineering design for the specific location.

The crossing pipe or sleeve should extend beneath and beyond the ditch with adequate cover extending to the road boundaries. If a pipe sleeve is used, the coated pipe shall be independently supported outside each end of the sleeve and insulated from the sleeve. The sleeve ends shall be sealed using a non-conductive material. The use of casings may not be compatible with cathodic protection systems and should therefore be reviewed by a corrosion control specialist. Pipe road crossings are normally installed by boring from a side excavation and the pipe and/or sleeve pulled through

(3) Pipelines constructed after the adoption date of this rule shall be designed and constructed in accordance with the American Society of Mechanical Engineers (ASME) Standard for pressure piping ASME B31.3 or B31.4 issued March 15, 1993, in effect during the time of construction or any other standard accepted by the Department.

Pipeline Regulations and Standards

The ASME/ANSI codes referenced below are the minimum requirements for the design, materials selection, construction, assembly, inspection, and testing for oil transfer piping. One item of note in all ASME/ANSI codes is the statement: "The designer is cautioned that the code is not a design handbook It does not do away with the need for the designer or for competent engineering judgment." The ASME/ANSI codes reference a number of other standards, specifications and recommended practices which should be followed, some of which are discussed below. In addition to these codes, various pipeline owners have developed their own standards which supplement, clarify, or go beyond the following codes. Design of a pipeline should be supervised by a qualified engineer.

Most cross country transmission pipelines are designed and operated acing as a minimum standard *ASME/ANSI B31.4 "Liquid Transportation Systems for Hydrocarbons, Liquid Petroleum Gas, Anhydrous Ammonia and Akohols* ". Piping in process plants is designed using the *ASME/ANSI B31.3* "Chemical Plant and Petroleum Refinery Piping" as a minimum standard.

Transfer pipelines may be designed, constructed and modified according to either of the above standards, depending on the operating pressures, throughputs, routing, public exposure (e.g., buried or above-ground), and other factors. *ASME/ANSI B31.3* includes a corrosion allowance for calculating pipe wall thickness.

API 570 'Piping Inspection Code - Inspection, Repair, Alteration, and Rerating of In Service Piping Systems". This code was developed for the petroleum refining and chemical processing industries, but may be used for any piping system.

49 CFR Part 195 "Transportation of Hazardous Liquids by Pipelines". This is a federal regulation and is applied to interstate pipelines. The regulation has incorporated the *ASME/ANSI B31.4* code by reference.

API RP 1102 "Recommended Practices for Liquid Petroleum Pipelines Crossing Railroads and Highways". This recommended practice is a requirement *of ASMI/ANSI B31.4.*

API RP 1109 'Recommended Practice for Marking Liquid Petroleum Pipeline Facilities': ASME/ANSI B31.4 advises this *API RP 1109* shall be used as a guide.

NACERP 01-69 "Control of External Corrosion on Underground or Submerged Metallic Piping Systems". ASME/ANSI B31.4 refers to sections of this recommended practice as a guide and for an adequate level of cathodic protection.

Pipeline Inspection

(4) Pipelines must be inspected in accordance with API 570, 1993, Piping Inspection Code. Inspections and Testing

Inspection and testing of a manufactured piece of equipment or component is carried out at various times throughout its service life: during the manufacturing process, at the time of installation in the pipeline, and at numerous times during its operation.

ASME/ANSI 31.3 and 31.4 include sections on inspection and testing, operation and maintenance procedures, and corrosion control. Depending on the applicable design code used in the pipeline design, these sections should be the minimum requirements for the pipeline.

API standards, which govern the manufacture of many pipeline components, define the minimum level of inspection and testing, and place the responsibility for compliance with the manufacturer. The purchaser may elect at the time of ordering to specify additional fabrication, inspection and testing by the manufacturer beyond that called for in the manufacturing standard, or to perform an independent inspection. It is common for the purchaser to identify specific points in the manufacturing process at which time the manufacturer is obligated to notify the purchaser to facilitate the purchaser's inspection.

Visual inspections of manufactured components are made at site upon receipt of the item, and during installation and commissioning. The manufacturer of pressure containment devices is required to perform a hydrostatic test to ensure the integrity of the component once put into service. These devices are often isolated from the field hydrostatic test of the completed pipeline by installing blinds at flanged connections of large components and by removing smaller components and temporarily plugging the line during the system hydrostatic test. Pipeline valves manufactured to API specifications may be field hydrostatically tested at a test pressure exceeding the maximum operating pressure rating of the valve by up to 50 percent, with the gate, ball, plug, or check partially or fully open. These valves should not be used in the closed position to contain test pressure exceeding 10 percent of the maximum operating pressure rating of the valve. The operator should check the allowable pressure differential as allowed by the valve's specifications.

During the operation of the pipeline, visual inspection of aboveground components should be made on a regular basis to check for leakage. The condition and performance of pumps should be monitored to give an early indication of developing problems.

When repair welding is performed on pressure components, the repaired components or sections of pipeline must be hydrostatically tested to prove the integrity of the repair <u>before</u> the repaired component is put back into service. Radiographic testing of the weld is acceptable where new piping is tied to piping which was previously tested.

New Pipelines

All components of a new pipeline are required to be examined and tested by suppliers and contractors, however, the assembled system shall be pressure tested for leaks and integrity prior to operation. *ASME/ANSI B31. 4 and B31.3, Chapter VI*, provides data on test methods and pressure requirements. The test fluid shall be disposed of in a manner acceptable to the Water Quality Program of the Department of Ecology.

Inservice Pipelines

ASME/ANSI B31.4, *Chapters VII and VIII*, and *API 570* should be utilized when establishing an inspection and testing plan. Some of the more important points from these codes are as follows:

1. Cathodically protected piping should be regularly monitored to ensure adequate levels of protection. *NACE RP-01-69* provides guidance for this monitoring.
2. *API 570* suggests the external condition of buried piping without effective cathodic protection should be determined by "smart or intelligent pigging" or by selective excavation according to the frequency in the following Table 10.1 If excavation is carried out, a six to eight foot section in areas most susceptible to corrosion should be exposed.

3. Internal corrosion inspection intervals for buried piping should be based on inspection of the above-ground portions of the pipeline and/or corrosion coupons.
4. Above-grade piping inspection should be a combination of regularly scheduled visual and thickness measurement inspections. The same locations should be used for repeated thickness measurement. These locations should be the areas of highest corrosion/erosion (i.e., "dead" legs for stagnant pipe segments, downstream of injection points, etc.). For guidance in conducting an external corrosion inspection *API 570* has developed a checklist.
5. Inspection frequency of above-grade facilities should be based on results of previous inspections, piping service classification, applicable jurisdictional requirements and judgment of the inspector. *API 570* provides some guidelines for inspection frequency and service definitions.

TABLE 10.1: INSPECTION INTERVALS-BURIED PIPE

Soil Resistivity (ohms-cm)	Inspection Interval (yrs)
Less than 2,000	5yrs
2,000 to 10,000	10 yrs
Greater than 10,000	15 yrs

Records should be maintained which include service classification, inspection intervals, thickness measurements, test information, maintenance activity, inspection information, and repair information.

Replacement Criteria for Pipelines

With a well documented operational history of a pipeline, a facility operator will have a statistical record and knowledge of any progressive deterioration of a pipeline.

Any difficulty in assuring continued safe operation without oil spits could result in a decision to reduce pipeline operating pressures, retest, repair, or replace all or certain sections of the pipeline. This decision may be guided by *the ASME/ANSI B31.4, Chapter VII "Operation and Maintenance Procedures*", *and ASME/ANSI B31 G "Manual for Determining the Remaining Strength of Corroded Pipelines*". However ANSI B31G examines only the size and distribution of corrosion pits and must be used in conjunction with the other required codes and standards.

Small pipeline repairs can be accomplished by cutting out a section of pipe and replacing it, or by grinding out defects and then filling the ground out area with weld metal. Small repairs are described in *API 570*.

The design, material selection, construction, assembly, inspection and testing of repairs should be completed utilizing the same code as the original pipeline (i.e., *ASME/ANSI B31.3 and B31. 4*).

If the pipeline rated operating pressure is reduced for any reason, the owner shall document the reasons with the design calculations involved and any repair procedure carried out.

As an alternative to complying with API 570, the facility must comply with the following requirements:

> **(a) Buried pipelines constructed after the adoption date of this rule must be coated. Coatings shall be designed and inspected to meet the following conditions consistent with the definition of best achievable protection:**
>
> > **(i) Coatings shall effectively electrically isolate the external surfaces of the pipeline system from the environment**
> >
> > **(ii) Coatings shall have sufficient adhesion to effectively resist underfilm migration of moisture.**
> >
> > **(iii) Coatings must be sufficiently ductile to resist cracking.**
> >
> > **(iv) The coating shall have sufficient impact and abrasion resistance or otherwise be protected to resist damage due to soil stress and normal handling (including concrete coating application, installation of river weights and anode bracelet installation, where applicable).**
> >
> > **(v) The coating must be compatible with cathodic protection.**
> >
> > **(vi) The coating must be compatible with the operating temperature of the pipeline.**
> >
> > **(vii) Coatings shall be inspected immediately before, during, or after pipe installation to detect coating faults. Faults in the coating shall be repaired and reinspected.**

The requirements of this section are designed to provide an alternative to complying with *API 570* requirements. The intent of this section is to address corrosion control. Figure 10.1 shows a flowchart intended to clarify the requirements of this section.

COMPLIANCE WITH *WAC 173-180A-100 SECTION (4)*

TRANSFER PIPELINE INSPECTION REQUIREMENTS

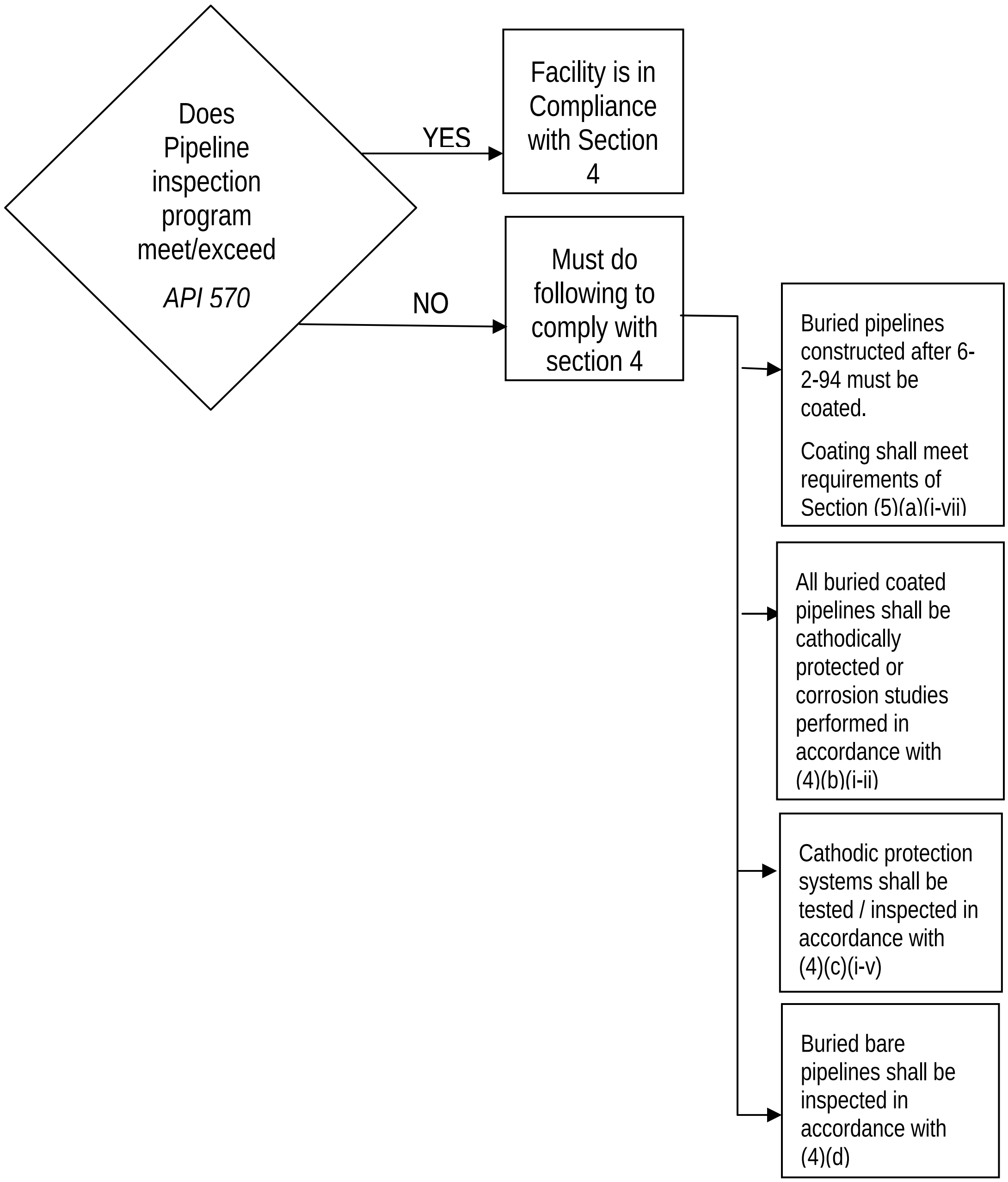


Figure 10.1

Corrosion Control

Steel pipe corrodes naturally by an electro-chemical process in the presence of oxygen and moisture. This corrosion proceeds as adjacent areas of the pipe develop a voltage differential from differences in the steel chemical composition and current is conducted between the adjacent areas by the moisture acting as an electrolyte. There is a loss of metal as the current leaves the anode area of the pipe and a serious loss of pipe wall thickness will occur over a period of time.

When steel pipe is buried, the corrosion process is assisted by the variations in oxygen and dissolved salts in the soil which create additional voltage differentials with corrosion cells. The corrosiveness of the soil can be determined by a measurement of soil resistivity. Lower levels are relatively more corrosive than higher levels.

The initial step in reducing corrosion of pipe above and below ground is to apply an adequate protective coating.

In addition to the protective coating applied to buried pipe, electro-chemical corrosion can be greatly reduced by applying cathodic protection. This is accomplished by burying anodes of carbon or zinc and connecting them to the pipe through a cathodic rectifier. As electric current flows from the anodes through the soil, the pipe remains intact and the anodes slowly decay. Buried steel pipe requires a potential of more than -0.85 volts to prevent corrosion: The output of a cathodic rectifier can be adjusted to meet the potential requirement and can provide coverage up to approximately 20 miles in each direction. *ASME/ANSI B31.4, Chapter VIII "Corrosion Control*", describes minimum protection requirements.

Sacrificial magnesium anodes without a power source will also supply a potential to reduce electrochemical corrosion of buried pipe in isolated areas without a source of electric service.

Pipe to soil potentials at test locations should be monitored and rectifiers adjusted or anodes replaced as required.

Internal pipe corrosion can also occur when oil containing sediment and water or a sulfate reducing bacteria is left in the line without movement for a prolonged period. In an idle line, the corrosion by water contamination slows down when the oxygen is used up but any bacterial corrosion is self sustaining and does not stop. Internal coating, scraper pigging, frequent line flushing or draining a pipeline between transfers or injection of bactericide with a corrosion inhibitor will provide protection against corrosion caused by bacteria.

External Corrosion Control

Coatings

Above-ground steel piping is usually protected by painting. Underground steel piping is protected by a variety of different plastic, tape, bitumen or epoxy coatings. These coatings are now being examined more critically to ensure the use of these products are suitable for human exposure and environmental safety. This has resulted in coatings being developed which remain bonded at higher temperatures and are resistant to oil exposure. To achieve proper bonding, the application method is extremely important (refer to the manufacturer's recommended installation instructions). Abrasive cleaning sand and other materials shall be properly disposed of to avoid contamination of local soil.

If tape and primer is selected for a coating, it may be machine wrapped on the pipe to achieve a smooth adhering application. Coatings may be hand wrapped after repair work. The selection of a fusion bonded epoxy or extruded polyurethane as a coating will require shop controlled conditions to apply the coating.

Following an inspection of the coating and repairs to any imperfections, the pipe shall be carefully handled during installation. An additional protective wrapping may be required for taped and fusion bonded epoxy coatings to reduce the possibility of damage during installation.

Types of Coatings for Underground Service

Coatings should be applied to the pipe immediately after an abrasive blast cleaning in accordance with the manufacturer's recommendation. Some of the common coatings found in the field are:

- Coal Tar Enamel - coal tar, with synthetic hardening additive. Sets up in 24 hours. Shop or field applied beside pipe ditch. Asbestos fiber no longer included.
- Polyethylene Tape and Primer - heavy polyethylene tape over a prime filler coat can be wrapped on as the pipe is being placed in the pipe ditch. Thin polyethylene tape deteriorates in presence of hydrocarbons.
- Extruded Polyethylene or polypropylene- installed under shop conditions. Not to be stored or installed above grade because of ultraviolet deterioration.
- Polyurethane Epoxy - fast setting sprayed on epoxy liquid. Toxic content may require protective handling methods.

Coatings for underground piping applications are usually inspected during and immediately after the application process, either in the factory or in the field just prior to installation: Repairs are done as necessary following the coating manufacturer's recommendation. Typical defects found are mechanical damage (scrapes, gouges, scratches, etc.), pinholes, blisters or disbonding, improper thickness. Care should be taken to properly repair any through-coating damage to the pipe metal itself especially in the case of thin-walled high stressed pipelines where stress-risers can lead to failures of the pipeline. Methods of inspection include visual, mechanical and electronic. Holiday detection instruments are commonly used in the pipeline industry.

(b) All buried coated pipelines shall have property operated cathodic protection which is maintained during the operational life of the pipeline system. Cathodic protection shall be maintained on pipeline systems which are out of service but not abandoned unless the operator can show that the pipeline integrity has been property monitored and secured as approved by the department prior to operation of the abandoned pipeline.

Pipeline owners or operators may perform a corrosion study to demonstrate that cathodic protection is not required as an option to installing cathodic protection. Corrosion studies shall follow the following guidelines as a minimum:

In the event of abandoning a piping system, the facility should be disconnected from all sources of the transported liquid and should be flushed clean the transported liquid and vapor with an inert material and the ends sealed.

(i) Corrosion studies shall be completed by a professional engineer with experience in corrosion control of buried pipelines, a NACE certified corrosion specialist or by a person knowledgeable and qualified to perform the required testing and inspection who is approved by the department

(ii) Corrosion studies for pipelines shall include at a minimum, the following:

(A) Pipeline thickness and corrosion rate for existing pipelines;

(B) Presence of stray DC currents;

(C) Soil resistivity/conductivity;

(D) Soil moisture content;

(E) Soil PH;

(F) Chloride ion concentration; and

(G) Sulfide ion concentration.

Corrosion Surveys

Following the installation of a buried coated pipeline, measurements of the voltage differential between the pipeline and a suitable soil reference electrode are taken at all test points along the pipeline at least annually and additionally whenever construction or similar activities are observed in the vicinity that may adversely effect the pipeline. NACERP-01-69 has recommendations for the survey procedures. Regular pipeline to soil surveys will assist in maintaining the system and locate any interfering potentials. Cathodic protection rectifiers (if in use) should be inspected every two months to verify that voltages and currents have not changed appreciably.

The buried pipe can be inspected for corrosion after it is placed in operation by inserting a internal inspection "smart pig" with the oil which will measure and record the pipe wall thickness. This device uses either electro-magnetic sensors or ultrasonic sensors. Internal inspection "Smart pigs" are commonly used in transmission pipelines but may have limited use for existing transfer pipelines when the pipeline configuration is limiting.

Recorded changes in wall thickness suspected to be caused by corrosion are examined by excavation at the indicated location. Wall thickness can also be measured externally using a hand held ultrasonic tool which is held against bare pipe. (Note: Only experienced personnel should take the thickness measurements due to the potential for error). If there is no external corrosion and depending upon the severity, a section of pipe may be cut out for internal inspection. Where the underground piping is not subjected to pigging, internal corrosion rates can also be routinely monitored by means of corrosion coupons anchored inside the piping at various test points.

Corrosion of above-ground piping can be monitored by regular ultrasonic inspection of pre-selected points in the piping system.

(c) All pipelines with cathodic protection are subject to the following requirements where applicable:

> **(i) Cathodic protection systems must be tested to determine system adequacy on an annual basis.**
>
> **Note: The National Association of Corrosion Standard *RP-02-85, "Control of External Corrosion on Metallic Buried, Partially Buried, or Submerged Liquid Storage Systems,"* may be used to comply with this section.**
>
> **(ii) Impressed current cathodic protection rectifiers must be inspected every two months.**
>
> **(iii) Where insulating devices are installed to provide electrical isolation of pipeline systems to facilitate the application of corrosion control, they shall be properly rated for temperature, pressure and electrical properties, and shall be resistant to the**
>
> **(iv) Buried pipeline systems shall be installed so that they are not in electrical contact with any metallic structures. This requirement shall not preclude the use of electrical bonding to facilitate the application of cathodic protection.**
>
> **(v) Tests shall be carried out to determine the presence of stray currents. Where stray currents are present, measures shall be taken to mitigate detrimental effects.**

NACE RP-01-69 provides a guide for cathodic protection systems survey. This corrosion survey shall also check for extraneous ground currents from other sources such as DC or AC power lines, rail lines, and other buried utilities and pipelines.

The buried pipeline may require insulating gaskets which are commercially available, installed at tie-in locations to allow test measurements and isolation from other systems.

(d) Buried bare pipelines shall be inspected in accordance with section 7 of API 570 dated June 1993. Pipeline thickness and corrosion rates shall be determined at an interval of no more than half of the remaining life of the pipeline as determined from corrosion rates or every five years whichever is more frequent. Pipeline thickness and corrosion rate shall be initially established within thirty-six months after the adoption date of this rule. The pipeline shall be operated in accordance with American Society of Mechanical Engineers (ASME) supplement to ASME B31G-1991 entitled "Manual for Determining the Remaining Strength of Corroded Pipe" for transmission pipelines issued June 27, 1991, API 570 dated June 1993 or a standard approved by the department.

Pipeline records should be consistent with *API 570* and should include the installation date, test data, operating pressures and flowrate, inspection dates, corrosion measurements, and any pipeline leaks or repairs. An investigation is normally carried out every five years to determine the extent and effect of corrosion.

To assess the rate of bare pipe corrosion, the owner may develop a program of investigation or excavation at regular intervals with a defined plan of non-destructive tests and wall thickness measurements. Whenever the pipeline is exposed for any reason, the owner examines the pipeline for evidence of external corrosion. This program may be assisted by installing a test bed with buried bare steel pipe coupons for fixture examination.

External corrosion can also be monitored by using a "smart or intelligent pig" if the pipeline is equipped with appropriate launchers and receiving traps.

Internal Corrosion Control

Internal corrosion occurs predominantly in low spots and the bottom quarter of a pipeline. Corrosion rate can be monitored by installing a coupon in the line and monitoring its rate of metal loss. Inhibitors can also be added to the hydrocarbon to reduce or eliminate the corrosion rate. Coupon monitoring should be used to monitor the effectiveness of inhibitors.

Cathodic Protection

Cathodic protection is not effective in controlling internal corrosion. Reducing internal corrosion may be accomplished through internal coatings or the injection of an acceptable corrosion inhibitor.

For an extended shutdown, a clean oil product may be placed in the line or it may be emptied, cleaned and the air displaced with an inert gas such as nitrogen.

(5) Whenever any buried pipe is exposed for any reason, the operator shall provide a nondestructive examination of the pipe for evidence of external corrosion. If the operator finds that there is active corrosion, the extent of that corrosion must be determined and if necessary repaired.

(6) Each facility shall maintain all pumps and valves that could affect waters of the state in the event of a failure. Transfer pipeline pumps and valves and storage tank valves shall be inspected annually and maintained in accordance with the manufacturers' recommendations or an industrial standard approved by the department to ensure that they are functioning properly. Valves shall be locked when the facility is not attended. Necessary measures shall be taken to ensure that valves are protected from inadvertent opening or vandalism if located outside the facility or at an unattended facility.

Maintenance of these Devices

Proper maintenance of pipeline equipment and components will extend their useful life and will contribute to the ease of operation and reliability of the pipeline.

Certain maintenance activities may be executed while the system is in operation, while others require that the component be isolated from the rest of the pipeline or that the system be shutdown at the time of the work Maintenance activities may be performed on a pre-defined schedule based on the owner's operating experience and the manufacturer's recommendations, or in some cases may be carried out upon detection of a specific problem.

Pipeline valves may at times exhibit incomplete shutoff of flow, difficulty in operation of moving parts, or leakage of fluid to the outside of the valve. Equipment such as pumps may develop problems of insufficient flow or pressure, decreased efficiency, vibration, noise, increased bearing temperature or leakage. All of these symptoms indicate the need for corrective action, whether it be simply fixing the problem or investigating further to determine the source of the problem and necessary course of action.

Manufacturers of equipment and components publish operation and maintenance manuals for their products which give detailed descriptions of maintenance procedures and recommended schedules, parts lists, and troubleshooting guidance. This source of information should be consulted by personnel who are involved in the maintenance work

Of particular importance with regard to prevention of fluid leakage are maintenance items such as tightening and lubrication of valve packing or replacement, as necessary, renewal of seats, replenishment of sealing compound, and tightening or replacement of gaskets at bolted connections.

Similarly for pumps, packing should be tightened or replaced, mechanical seal rings may be worn and require replacement, and gaskets for the pump casing, mechanical seal and flanged nozzles may need to be tightened or changed. Gaskets should always be replaced if the bolted connection has been disassembled.

Cast iron pumps, valves and piping is not recommended for hydrocarbon service.
Replacement Criteria for Pumps and Valves

With proper care in operation and maintenance of pipelines, current designs, materials and manufacture of components facilitate long service life. Parts that are subject to mechanical wear, fluid erosion, corrosion, or other deterioration are generally replaceable. The operating and maintenance cost for major equipment should be monitored on an ongoing basis to determine when replacement is economically justified. Earlier replacement may be warranted in cases where mechanical damage is not repairable due to time constraints or cost. Availability of spare parts may change over time, in which case replacement of the equipment should be considered.

(7) A written record must be kept of all inspections and tests covered by this section.

(8) Facilities shall have the capability of detecting a transfer pipeline leak equal to eight percent of the maximum design flow rate within fifteen minutes for transfer pipelines connected to tank vessels. Leak detection capability shall be determined by the facility using best engineering judgment Deficiencies with leak detection systems such as false alarms must be addressed and accounted for by the facility. Facilities may meet these requirements by:

> **(a) Visual inspection provided the entire pipeline is visible and inspected every fifteen minutes; or**
>
> **(b) Instrumentation; or**
>
> **(c) Completely containing the entire circumference of the pipeline provided that a leak can be detected within fifteen minutes; or**
>
> **(d) Conducting an acceptable hydrotest of the pipeline immediately before the oil transfer with visual surveillance of the exposed pipeline every fifteen minutes; or**
>
> **(e) A combination of the above strategies; or**
>
> **(f) A method approved by the department which meets the standard identified in this section.**
>
> **Leak detection system operation and operator response must be described in the facility operations manual.**

The rule states that "facilities shall have the capability of detecting an 8% transfer pipeline leak within 15 minutes". The leak size percentage is based on the design maximum flowrate through the transfer pipeline equaling 100%. Although the rule does not state the detection time for leaks that are larger or smaller than 8%, the intent is that larger leaks shall also be detected within 15 minutes. Smaller leaks will require more time for detection. The rule also specifies that "leak detection capability shall be determined by the facility using best engineering judgment". Some of the following methods for detecting leaks in transfer pipelines may, depending on the circumstances, satisfy the requirements of the rule.

Material Balance and Pressure Wave Systems

A report titled 'Evaluation of Mass Balance Leak Detection Systems With Respect to Oil Transfer Pipelines" is attached as Appendix J.

The report evaluates various methods of measuring transfer pipeline flow available during the reports development in 1993 and provides an estimate of leak detection accuracy and the installed cost of the measurement devices and the leak detection software and hardware.

Two pressure wave leak detection are also discussed in the report.

Hydrocarbon Sensing Cables

Sensing cable systems generally operate on the principle that absorption of hydrocarbon by the cable causes a change in electrical properties. The absorption process may be too slow to satisfy the requirement that an 8% (or larger) leak is detectable within 15 minutes but these systems can detect and locate leaks that are too small to be detected by material balance systems. The sensing cables have to be installed so that they will contact leaked oil. Once exposed to hydrocarbon the cables must be replaced.

Gas Detection Tube

A sensor tube that allows hydrocarbons to enter by diffusion but is impervious to water is installed so that it will contact leaked oil. Dry air is pumped through the tube past a hydrocarbon detector to detect a pipeline leak Small leaks can be detected and located by filling the tube rapidly with dry air, stopping the air flow to allow time for hydrocarbon diffusion and then displacing the tube contents at a known rate past the hydrocarbon detector. The diffusion rate may be too slow to satisfy the requirement that an 8% (or larger) transfer pipeline leak is detected within 15 minutes.

Acoustic Emissions

Piezoelectric transducers are attached to the pipeline at intervals of 100 to 500 feet to detect the mechanical waves that propagate along the pipe wall during a leak The transducer signals are connected to a host computer via co-axial cable. The amplitude and possibly the frequency of the mechanical waves will depend on the pipeline pressure and the size of the leak Interfering signals can be caused by pumps and throttling valves.

Visual Inspection

Facilities with above ground transfer pipelines that can be continuously observed during a transfer could meet the rule requirement that a 8% leak is detected within 15 minutes. Additional lighting and television cameras may be installed to use this method and meet the requirement.

Hydrotest before transfer

This method of leak detection is intended for low use transfer application (1-3 transfers/year). The pipeline must have good valves capable of blocking pressures at 10-15% over the operating pressure. The intent of this requirement is to assure pipeline tightness prior to transfer. Visual surveillance of the exposed pipeline must be maintained during the transfer operation.

Chapter 11

WAC 173-180A-110 INSPECTIONS

The department may verify compliance with this chapter by announced and unannounced inspections in accordance with RCW 90.56.410. During an inspection the department may require the facility to provide proof of compliance by producing all required records, documents as well as demonstrating spill prevention equipment and procedures required by this rule.

Chapter 12

WAC 173-180A-120 RECORDKEEPING

Records required by this rule shall be maintained and available for a minimum of three years. Storage tank and pipeline records shall be maintained for the life of the equipment Records shall be available to the department for inspection or photocopying upon request.

Records may be hard copies, kept in a computer or computer disk, or other electronic device.

Chapter 13

WAC 173-180A-130 NONCOMPLIANCE

Any violation of this chapter may be subject to the enforcement sanctions of chapters 90.48 and 90.56 RCW.

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Chapter 14

WAC 173-180A-140 RULE REVIEW

The department shall review the requirements of this section every five years to ensure that best achievable protection of public health and environment is being achieved. This review shall include a review of current and updated industry standards, federal and state regulations, equipment and operational procedures.

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Chapter 15

WAC 173-180A-150 SEVERABILITY

If any provision of this chapter is held invalid, the remainder of this rule is not affected.